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General Chapters:

1	**LNG Pricing Disputes: The Lessons From Europe** – Matthew Saunders & Ronnie King, Ashurst LLP		1
2	**Developments in the North American Oil and Gas Sector** – John P. Cogan, Jr. & Carlos Morán, Stone Pigman Walther Wittmann PLLC		5

Country Question and Answer Chapters:

3	**Albania**	Gjika & Associates Attorneys at Law: Gjergji Gjika & Lareda Zenunaj	11
4	**Angola**	ALC Advogados: Irina Neves Ferreira & Sofia Cerqueira Serra	20
5	**Argentina**	Estudio Randle / Stone Pigman Walther Wittmann PLLC: Ignacio J. Randle & Carlos Morán	29
6	**Austria**	Schoenherr: Bernd Rajal & Dagmar Hozová	41
7	**Brazil**	Rolim, Viotti & Leite Campos Advogados: Luis Gustavo Miranda & Paulo Teixeira Fernandes	52
8	**Canada**	Blake, Cassels & Graydon LLP: Kevin Kerr & Christine Yick	61
9	**Croatia**	Schoenherr: Bernd Rajal & Petra Šantić	73
10	**Denmark**	Windahl Sandroos & Co.: Bo Sandroos	90
11	**France**	Jeantet: Thierry Lauriol & Constance Guyot	99
12	**Gabon**	Project Lawyers: Jean-Pierre Bozec	120
13	**Greece**	KLC Law Firm: Dr. Vassilis Karagiannis	129
14	**Greenland**	Windahl Sandroos & Co.: Bo Sandroos	137
15	**Indonesia**	SSEK Legal Consultants: Fitriana Mahiddin & Syahdan Z. Aziz	144
16	**Italy**	Ughi e Nunziante – Studio Legale: Fiorella F. Alvino & Giovanna Branca	153
17	**Mexico**	Rodríguez Dávalos Abogados (Consultores en Energía RDA, S.C.): Jesús Rodríguez Dávalos & Raúl Fernando Romero Fernández	165
18	**Moldova**	Schoenherr: Andrian Guzun & Bernd Rajal	174
19	**Mozambique**	Henriques, Rocha & Associados: Paula Duarte Rocha & Tiago Arouca Mendes	184
20	**Norway**	Advokatfirmaet Simonsen Vogt Wiig AS: Bjørn-Erik Leerberg & Frode Vareberg	195
21	**Portugal**	Morais Leitão, Galvão Teles, Soares da Silva & Associados: Tomás Vaz Pinto & Claudia Santos Cruz	205
22	**Romania**	Pachiu & Associates: Raluca Mustaciosu & Vladimir Plugarescu	213
23	**Serbia**	Moravčević, Vojnović and Partners in cooperation with Schoenherr: Miloš Laković & Aleksandra Petrović	226
24	**South Africa**	Bowmans: David Forfar & Luke Havemann	236
25	**Turkey**	Türkoğlu & Çelepçi in cooperation with Schoenherr: Levent Çelepçi & Murat Kutluğ	245
26	**United Arab Emirates**	Dentons: Mhairi Main Garcia	253
27	**United Kingdom**	Ashurst LLP: Philip Thomson & Julia Derrick	264
28	**USA**	Stone Pigman Walther Wittmann PLLC: John P. Cogan, Jr. & James A. Cogan	284
29	**Venezuela**	Torres, Plaz & Araujo: Juan Carlos Garantón-Blanco & Valentina Cabrera Medina	296

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LNG Pricing Disputes: The Lessons From Europe

Matthew Saunders

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Current market circumstances and forthcoming changes in the LNG industry will likely lead to an increase in the number of parties seeking to renegotiate the pricing provisions in their long-term LNG supply agreements. The European gas market has, for a number of years, been the main battleground for price reopener disputes. This chapter explores the lessons that can be taken from the European gas pricing experience and sets out some of the key considerations to be borne in mind by those likely to find themselves engaged in renegotiations of their long-term LNG commitments including, in particular, those relating to pricing and volume flexibility.

According to the Oxford Institute for Energy Studies (OIES), one of the best informed observers of global gas markets, the LNG industry is on the verge of "radical" and "fundamental" change. In its September 2016 publication, *The Great Reconfiguration*, the OIES notes that dramatic changes are set to overturn more than five decades of industry practice, including – crucially – the model of LNG long-term sale and purchase agreements (SPAs) where pricing is linked to oil prices. The OIES cites two main potential causes of the pending changes: significant new LNG export capacity, which is due to come on stream in various parts of the world; and a slowing down of Asian demand.

Similarly, in autumn 2016, the *LNG Journal* noted (by reference to the latest analysis from the International Energy Agency) that: "The oversupply situation in liquefied natural gas markets that emerged in 2015 is worsening in 2016 and will not substantially improve until 2019 at the earliest".

The excess of LNG resulting from such supply-demand imbalance is expected to affect both the pricing and other contractual dynamics in long-term LNG SPAs (including, in particular, terms relating to flexibility).

The experience of the European natural gas markets over the past decade shows that any significant attempts to "reconfigure" existing contractual arrangements are likely to give rise to disputes. Two of the most likely subjects for dispute are those of pricing and related contractual flexibility, particularly as to volume, since those factors go to the core of whether a contract is profitable or not.

The experience of European natural gas markets since 2008 has been one of a dramatic upswing in the number of disputes, many of which have ended up in international arbitration, arising from the invoking of "price reopener" clauses in gas SPAs. The effect of such widespread recourse to arbitration mechanisms has been the resetting of prices by arbitration tribunals and, on occasion, significant changes being made to other elements of pricing formulae which has provoked controversy as to whether such changes are properly within an arbitration tribunal's jurisdiction.

The considerably adversarial nature of the arbitration process has also impacted upon the historically consensus-driven approach that has prevailed in the gas industry, which has a relatively small number of players and, until recently, has seen shared assumptions as to what is an acceptable "*modus operandi*" for commercial and contractual negotiation.

There are a number of lessons that can be drawn from the European natural gas experience and applied to LNG renegotiations and disputes in other regions. There are, of course, many significant differences between the contracting styles and commercial contexts that apply to natural gas sales arrangements in the European market and LNG sales arrangements in the global markets, but there are enough features in common and sufficient similarities of approach to the resolution of disputes for the study and analysis of the European gas market experience to potentially pay significant dividends – the lessons that can be drawn may maximise a party's chances of success in both renegotiations and disputes.

Europe's "Perfect Storm"

The European experience of an upswing in gas price arbitration came about by way of a "perfect storm" emerging from the global financial crisis of 2008. The key elements were:

- liberalisation of the European gas market pursuant to the EU's Third Energy Package (combined with enforcement steps being taken by national regulators), which led to the development of gas trading hubs and the creation of both physical and administrative infrastructure capable of supporting spot trading of gas and thus an increase in gas-to-gas competition;
- a reduction in demand for gas arising from the slowdown of the European economy associated with the global financial crisis;
- a policy-driven increase in the role of renewables in the generating mix;
- technological developments supporting the availability of gas from non-conventional sources, leading to an increase in supply; and
- a resulting "decoupling" of spot market prices for gas from traditional oil-linked prices (where it had been historical practice to link the price of gas to that of alternative fuels, particularly oil products).

As a result, players sought to renegotiate the price at which they had committed – often for a lengthy period of time – to take gas. In many cases, negotiations gave way to arbitration.

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Although there exists a significant diversity of approach (extending to gas SPAs without any price reopener provision and some that contain only contractual hardship clauses), the European gas arbitration community has largely adopted a common approach to resolving these pricing disputes. It is this that enables wider lessons to be taken as to how parties dealing with LNG disputes may benefit.

Applicable Legal Principles

Although no single standard exists for European gas price reopener clauses, there are significant similarities in the approach to their drafting and interpretation. It is relevant that long-term gas sales agreements are predominantly continental European creatures, with few UK long-term contracts because of the much earlier liberalisation of UK gas markets. The effect of this is that the gas price arbitration world has been significantly influenced by civil law.

This is significant because it means that the civil law approach to issues such as document production, or the extent of a tribunal's jurisdiction to amend contractual provisions other than those relating simply to price, may prevail in LNG disputes, even where the governing law is not a civil law one.

Contracts are often vague as to how far a party is under an obligation to negotiate "in good faith" and what the implications may be if it can be shown not to have done so (it is relevant that civil law contract regimes may impose an obligation to negotiate in good faith even if one is not expressly provided for in the contract).

Revision of price (and other contract conditions) may also be available under certain civil law regimes where they have been chosen as the governing law of the contract. Certain civil law regimes grant a right to adjust the contractual bargain where changes unforeseeable at the time the contract was entered into have the effect of causing "unreasonable hardship". In extreme cases, the contract may be held to be ineffective as a whole. Such contractual rights are perhaps most clearly available in the Scandinavian context, applying section 36 of the relevant contracts act and the Scandinavian contractual doctrine of failed assumptions. Although such laws may be less commonly applicable in the LNG world, it pays to understand their implications.

Specific Price Reopener Lessons to Apply

Obligations to Negotiate

One key lesson that can be taken from the European gas pricing experience is the significance of express obligations to negotiate. It will be particularly important that negotiation obligations are adhered to where the fact of negotiation having taken place may be a contractual precondition to commencing an arbitration. To run an arbitration and only at the end discover there was no jurisdiction, because a necessary precondition to the commencement of the arbitration process was not met, may prove to be an extremely expensive mistake.

Whether or not the governing contract law recognises the existence of an obligation to negotiate, or dismisses it as an unenforceable "agreement to agree", will commonly be a significant distinction between civil and common law governing laws.

Evidence of Trigger

Another lesson is the fact that a party will commonly be expected to provide a measure of support for its assertion that a trigger for the resetting of a price has been met, including some degree of clarification as to the relevant market in which the inability to market gas economically has arisen. The contract itself may be vague on the level of substantiation to be given, but the applicable law may provide guidance.

Confidentiality

A further lesson is that close attention should be paid to requirements of confidentiality. Pricing formulae are contractual terms of the highest commercial sensitivity. Does the contract provide for material to be kept confidential? What degree of confidentiality will attach to documents that are provided to lawyers and experts or to the tribunal? What is the status of documents produced under compulsion through a document production exercise? How far can commercial secrecy be an effective objection if the counterparty makes an application for production of documents to the tribunal?

The key lesson is that these points should either be agreed with the counterparty or be the subject of an early procedural ruling from an arbitration tribunal. That way, surprises can be avoided.

Economic Evidence

Of prime importance is the need carefully to prepare the economic evidence that supports the claim (or which will be needed to respond to an anticipated claim), particularly expert economic evidence. There is a finite pool of experienced testifying economics experts, and instructing the right team early on can bring significant advantages. It would be folly to commence a price review without understanding how far the economic analysis supports it.

Alongside economics experts, it may be necessary to adduce factual testimony or possibly expert testimony as to industry practice – experience suggests there is a particularly limited pool of industry experts with relevant recent experience. Tribunals may find evidence from an experienced commercial negotiator or contracts manager more compelling than that from a "hired gun" consultant.

Early Input From Legal Counsel

From the outset, there should be input from counsel experienced in gas pricing disputes – their full involvement from an early stage will assist in establishing and maintaining legal privilege (thus protecting documents from compulsory production) and will ensure that the correct early – and key – decisions are taken.

The Attitude of Arbitrators

One result of the growth in gas price arbitrations has been the establishment of a "community" of legal and industry practitioners with shared experience of the interpretation of relevant clauses and the running of arbitrations. This "community" comprises not only specialist arbitration lawyers in leading arbitration practices, but also expert economists and a "cadre" of arbitrators who have experience in disputes often involving much more economic than legal controversy and which consequently require a degree of familiarity with economic principles.

It is quite likely that these same arbitrators – because of their gas sector experience – will be appointed and that – at least initially – they will adopt similar approaches to those developed in the European gas pricing context.

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Alongside the choice of arbitration counsel, thought should be given from the outset as to the choice of arbitrator to be nominated and to the preferred candidates for chairman.

Points to consider include whether a common or civil law background is preferred and whether previous gas pricing experience, or experience of economics-based disputes, is necessary/desired. Careful research may provide useful intelligence as to an arbitrator's likely attitude to issues such as document production – whether it will be restricted to those issues upon which a requesting party bears the burden of proof or whether it will be more widely available (for example, where a legitimate line of inquiry involving a defined and narrow class of documents is established).

Price Review or Rewriting the Parties' Bargain?

A more fundamental issue worthy of research is the attitude an arbitrator is likely to take to his or her jurisdiction; does it extend to merely adjusting the price or is there a risk that the arbitrator will go further and rewrite other elements of the price formula? Arbitration agreements are commonly imprecise as to the jurisdiction that is granted to an arbitration tribunal. This question is normally of little significance given their role is clearly to adjudicate the dispute, but the position is more complex (and controversial) in a pricing dispute.

It is important to consider how far the right to set a new price extends and whether it encompasses the arbitrator being able to change other elements of the pricing arrangements; for example, the point of reference from a basket of oil products to prices achieved on a particular gas trading hub. Critics contend that such actions amount to much more than price adjustment and represent impermissible rewriting of the parties' contractual bargain. Proponents contend that only through such steps can tribunals properly take account of changed circumstances as fundamental as the decoupling of gas prices from oil pricing.

Parties are well advised to agree at the outset of an arbitration whether they actually wish to grant such wide-reaching powers to a tribunal comprised of arbitration lawyers who may have negligible commercial experience as to the implications of the changes they impose.

There is also sense in clarifying how far back a tribunal may look – must it restrict its analysis of evidence as to market changes to that available between the date of the last review and the invoking of the current process or may it also look at information available since? To what extent is the future relevant and is evidence required as to the likely impact of the changes relied upon in the future? Should the tribunal be aiming to set a price that renders the contract economically viable until the next point at which it can be reopened?

Looking Forwards

It may very well be the case that in due course those responsible for adjudicating LNG disputes "steer their own course" and develop approaches unique to the LNG market. However, at least initially, it is likely that approaches similar to those experienced in European natural gas pricing disputes will prevail. It is because of the "proving ground" it has become for gas disputes that lessons from the European gas pricing experience can usefully be applied in order to maximise the chances of winning.

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Developments in the North American Oil and Gas Sector

John P. Cogan, Jr.

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The Continent Taken as a Whole

Since the dramatic decline in the global price of crude oil began in 2014, the North American Oil & Gas Sector has suffered commensurately. A wave of declining capital budgets, job losses and bankruptcies has given vent to much pessimism, at least for the short term. However, it is our view that the fundamentals exist for a revival of a healthy Oil & Gas Sector in North America in the fairly near future. The important question is, "When?" The price for West Texas Intermediate ("WTI") crude oil, the benchmark price for North American crude, hit a 12-year low in the early part of 2016 at the mid-20-dollar level. At the time of this writing, the WTI price has climbed to the mid-50-dollar range. Whether that price can be supported and lead to further increases is a question yet to be answered. The general consensus is that, for the Oil & Gas Sector to recover fully, the price must rise to something over 60 dollars a barrel and be sustained for significant periods at that level or higher.

However, as drilling costs decline, an acceptable supply/demand equilibrium may be reached at a lower price. These costs have indeed declined significantly in recent times due to stiff competition for the provision of oil field services and increased efficiencies.

The shale revolution in the United States was considered a miracle in terms of its contribution to the goal of making North America relatively independent of foreign-sourced supplies but, ironically, it has also contributed to the short-term glut of supplies, exacerbating the price declines. Related events in Mexico and Canada have contributed to the overall sense of malaise currently being experienced in the entire region.

The United States-Mexico energy trade relationship has recently undergone a dramatic change – Mexico is now a net importer of hydrocarbons from the U.S. 16.5% of U.S. oil product exports go to Mexico. United States' energy exports to Mexico are now more than twice the value of its imports. Mexico sells crude to the U.S., while the U.S. sells natural gas and fuels to Mexico (more than half of Mexico's consumption). In 2015, Mexico increased its volumetric net natural gas pipeline imports by almost 50% (the largest increase worldwide). Mexico has been building an extensive pipeline network to import even more natural gas from the United States. Mexico is expected to increase its natural gas liquids imports (propane, methane and ethane) from the United States and Canada. At the same time, United States' companies (nine) have won more E&P contracts in Mexico than companies from any other countries (excluding Mexico itself). Canadian companies rank 4th in that list with two companies already having executed Mexican E&P contracts. United States and Canadian firms also have substantial investment plans in Mexican natural gas distribution, power generation and downstream projects in Mexico.

The United States' biggest energy trading partners are not members of OPEC, but Canada and Mexico. The three countries are currently involved in renegotiation of the 23-year-old North American Free Trade Agreement ("NAFTA"). Energy issues are a significant point in the NAFTA discussions, which are expected to continue well into 2018. Although President Trump has threatened to pull the United States out of NAFTA entirely, proponents of free trade (including most segments of the energy industry) hope to win the day and North America will retain the benefits of NAFTA albeit in a somewhat revised form.

One external factor influencing the North American energy market was OPEC's announcement of production cuts in late 2016. The length of time that these cuts can be effectively maintained will have a profound impact on the well-being of the North American energy market.

Conversely, what happens in the energy sector in each country in North America has a profound impact on the energy scene in the rest of the world. In the United States, the big news focuses around new discoveries and exports. In Canada, pipeline constraints brought on by physical and political barriers have kept a lid on too much optimism for the short term. Much has been written about these developments, but one of the most noteworthy events in the North American energy scene has been the opening of the Mexican energy sector to private investment at the end of 2013 and the continued development of the Mexican energy sector since then. This is truly a monumental event for all of North America and, indeed, for the world.

Mexico

More than seven-and-a-half decades after the nationalisation of its oil industry, Mexico finally put an end to the monopoly of State oil company Pemex, and opened its upstream, midstream and downstream sectors to private domestic and foreign investment. The scope of the constitutional reform enacted in December 2013 reached farther than expected. Most significantly, private and foreign companies are now allowed to engage in exploration and production activities.

The Mexican energy reform has attracted the attention of the industry worldwide. Mexico's abundant resources, strategic location and stable economy make the country particularly attractive to investors. Oil majors are interested in Mexico's vast offshore reserves, particularly those in deep waters in the Perdido Fold Belt, where a trio of discoveries were confirmed in October 2015 and where there has been very little activity as compared to the U.S. side of the border, due to lack of technical and financial capabilities. Likewise, independent shale-focused companies are interested in the Burgos Basin, which is believed to be a continuation across the U.S.-Mexico border of the prolific Eagle Ford shale play in

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Texas. The U.S. Energy Information Administration has estimated Mexico's shale gas reserves as the 6th highest worldwide.

Pemex's oil production has been in a continuous and rapid decline after reaching its peak in 2004. However, Mexico continues to be blessed with abundant resources and is still a world-class crude oil producer and exporter. Its 3P reserves exceed 112 billion barrels of crude oil equivalent ("BOE"), 84 billion of which are yet to be made available for tender.

Mexico is interested in attracting international companies to reverse its declining production, and has sufficient proved oil reserves to do so (10.8 billion barrels, the 18th largest in the world). Mexico's oil-production rate in 2016 was 2.1 million barrels per day. The Mexican government expects new players to increase production in the upcoming years. The International Energy Agency and the U.S. Energy Information Administration, respectively, have estimated that Mexico's long-term oil production has the potential to reach 3.4 and 3.7 million barrels per day by 2040.

Since December 2014, Mexico's National Hydrocarbon Commission ("CNH") has been conducting international bidding rounds successfully and transparently – awarding more than 72 contracts to companies from 18 countries, including BHP, BP, Chevron, CNOOC, DEA, Ecopetrol, ENI, ExxonMobil, Fieldwood, Lukoil, Murphy, Ophir, Pan American, Petronas, Premier Oil, Repsol, Shell, Statoil, Talos, and Total. Thirty-three contracts have been awarded to Mexican companies, such as Carso Oil & Gas, Citla Energy, Diavaz, Jaguar, Sierra, and Petrobal. Winning bidders have committed investments for more than $60 billion. The average government take of the awarded contracts is 70%.

CNH is currently working toward standardising and simplifying the administration of bidding procedures in general. For example, allowing potential bidders to nominate blocks for future bidding rounds, using a standard size for contractual areas by type, simplifying the certification of capabilities and bidder pre-qualification processes, and standardising the schedule of bidding rounds. CNH intends to drastically increase the number and size of blocks to be awarded in 2018, as you may note from the descriptions of Rounds 2.4 and 3.1 below.

Round 1

The first bidding round for oil and gas exploration and production ("E&P") contracts ("Round One") was launched in the last quarter of 2014. Round 1 originally offered 169 blocks to bidders – 109 blocks for exploration and 60 blocks for production, covering an area of around 28,500 km^2. The resources originally offered were estimated at around 3.8 billion BOE of 2P reserves and about 14.6 billion BOE of prospective reserves. The areas were chosen due to their potential to increase the production of oil and gas in the short term, to incorporate new reserves and to increase prospective resources.

Round 1 was split into four phases, namely Rounds 1.1, 1.2, 1.3 and 1.4.

Round 1.1 commenced on 11th December 2014 by the publication by CNH of the relevant call for bids (*convocatoria*) and request for proposals (*bases*). Round 1.1 included 14 contractual areas for exploration and extraction of hydrocarbons in shallow waters under production sharing contracts; 25 bidders (individually or as a consortium) pre-qualified for the historic first round.

The event for the opening of the bids took place on 15th July 2015, resulting in the awarding of two contracts, both of which were awarded to a consortium formed by Sierra, Talos and Premier. In 2017, this consortium made a discovery of prospective resources between 1.4 and 2 billion BOE.

Round 1.2 started on 27th February 2015: nine shallow-water fields were grouped in five contractual areas. Bids were opened on 30th September 2015, resulting in the awarding of only three production sharing contracts. The winning bidders were: ENI; the consortium formed by Pan American and E&P Hidrocarburos y Servicios; and the consortium formed by Fieldwood and Petrobal. ENI recently made an important discovery of light crude in its awarded area. ENI estimates the prospective resources discovered at 1 billion BOE – exceeding the expectations that CNH had for this field, considering that Pemex had explored the area several years ago and that Pemex operates a contiguous block.

In Round 1.3, CNH offered 25 onshore mature fields under licence contracts, all of which were awarded on 15th December 2015. Sixty companies (40 Mexican) registered for this bidding process.

Round 1.4 comprised 10 deep-water contractual areas in Mexico's exclusive economic zone in the Gulf of Mexico – four of which are located in the Perdido Fold Belt, near the U.S.-Mexico maritime boundary. Prospective resources in these areas amount to 10.8 billion BOE. Twenty-Six companies have pre-qualified (16 as operators). CNH awarded eight licence contracts in December 2016 to: CNOOC (two contracts) and the consortia formed by Total and ExxonMobil; Chevron, Pemex and Inpex; Statoil, BP and Total (two contracts); PC Carigali and Sierra; and Murphy, Ophir, PC Carigali and Sierra.

Round 2

Round 2.1 concluded in March 2017. This was the third bidding round for shallow-water fields. The blocks offered for exploration and production were larger in comparison to those in previous shallow-water rounds (594 km^2 on average, as opposed to 300 km^2). CNH improved numerous terms of the production sharing contract to attract more bids. The relevant 15 blocks were in the Gulf of Mexico off the States of Veracruz, Tabasco and Campeche, and were chosen considering the industry's feedback. The blocks had aggregate prospective resources in the region of 1,587 million BOE. CNH awarded 10 contracts among: ENI, Lukoil and the consortia formed by Pemex and DEA; PC Carigali and ECP Hidrocarburos; ENI, Capricorn Energy and Citla Energy; Pemex and ECP Hidrocarburos; Capricorn Energy and Citla Energy; Repsol and Sierra; ENI and Citla Energy; and Total and Shell.

Under Round 2.2, CNH offered 12 onshore contractual areas under licence contracts, nine of them for gas exploration and production near the U.S. border (in the State of Tamaulipas) and three for oil and gas exploration and production near the Guatemala border (in the States of Tabasco and Chiapas). CNH commenced this bidding round in August 2016 and announced the winners in July 2017. The consortium formed by Jaguar and Sun God won six contracts, and the one formed by Iberoamericana and PJP4 won an additional one.

Round 2.3 resulted in the awarding in July 2017 of 14 licence contracts for onshore blocks. The winners were Carso Oil & Gas and Jaguar (five contracts) as single bidders, as well as the consortia formed by Iberoamericana and PJP4 (two); Newpek and Verdad Exploration (two); and Shandong, Sicoval and Nuevas Soluciones.

The ambitious Round 2.4 is still ongoing. Under this round, CNH is offering 29 deep-water blocks (under licence contracts) distributed between the main Mexican oil provinces in the Gulf of Mexico. The total area being offered covers around 70 km^2 (17 million acres, three times the acreage offered under Round 1.4) with prospective resources in excess of 4 billion BOE (twice as much as the prospective resources actually awarded under Round 1.4). CNH is scheduled to open bids on 31st January 2018.

Round 3

Round 3.1 commenced in September 2017 and will conclude in

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March 2018. Thirty-five shallow-water areas in the Gulf of Mexico will be awarded under licence contracts. The aggregate area comprises more than 26,000 km^2 (six million acres) throughout the Gulf of Mexico. CNH estimates the total prospective resources on offer at 1.9 billion BOE.

Migrations and Farm-outs

Under the new Mexican oil and gas legal framework, Pemex is allowed to migrate the entitlements it managed to retain after the Energy Reform to the new oil and gas contractual regime created thereby. In this case, SENER must propose the model contract and the Ministry of Finance must set the applicable fiscal terms. The first entitlement migrated to the new scheme relates to the Ek-Balam field. On 2nd May 2017, CNH and Pemex executed the relevant production sharing contract.

Pemex is also allowed to partner with other companies to develop the entitlements it migrates into contracts. However, CNH must select the relevant partner through a bidding round – except for Pemex's entitlements already operated by third parties under integrated (risk) service contracts (known as CIEPs) or financed public works contracts (known as COPFs) executed prior to 12th August 2014 (date of entry into force of the Hydrocarbons Law). This partner selection process is known in Mexico as a Pemex farm-out bidding round.

The first farm-out bidding round resulted in the execution in March 2017 of a licence contract by and between CNH, Pemex and BHP regarding the 1,285 km^2 Trion deep-water block, which is contiguous to one of the contractual areas awarded under Round 1.4.

In October 2017, Cheiron Holdings Limited and DEA won the farm-out bidding rounds regarding Pemex's onshore fields Cárdenas-Mora and Ogarrio, respectively.

Currently, CNH is conducting a farm-out bidding round regarding Pemex's Nobilis-Maximino block in the Perdido Foldbelt.

Unitisation

The legal and regulatory framework deriving from the Energy Reform allow the Mexican Ministry of Energy to force E&P contractors and entitlement holders (interest owners) to unitise their fields when a reservoir straddles the boundaries of their contractual area or entitlement, with a view to operate efficiently and maximise production. In their E&P contracts, contractors expressly consent to report the discovery of common reservoirs, to seek a voluntary unitisation agreement (subject to the Ministry's approval) and/or to abide by a compulsory unitisation order by the Ministry. Operations conducted on a unitised field count toward the fulfilment of the minimum work obligations in all the contractual areas involved, irrespective of the location of the wells and who the operator of the unit is.

The Ministry of Energy recently published a draft of its unitisation guidelines, which elaborate on the procedures that need to be followed to achieve the unitisation of common reservoirs, as well as the terms, conditions and principles applicable to unitisation orders and agreements.

The draft guidelines make it clear that the parties to a unitisation agreement may agree on any methodologies for the determination of their participation interest in the unit, including but not limited to: relative amounts of oil or gas in place under each block; hydrocarbon pore volumes; and estimated ultimate recovery. The Ministry may use any of those methodologies to allocate costs and production between the blocks when it imposes a unitisation order upon the interest owners of those blocks.

In order to calculate the State's share in the production, royalties and taxes, the income and expenditures allocated to a party to the unitisation agreement by reference to its participation interest in the unit will be deemed to be income arising from and expenditures incurred in the contractual area or entitlement of that party.

The draft guidelines recognise the international practice of executing a pre-unitisation agreement at the time of discovery, which is followed by the execution of a unitisation agreement once a development plan has been agreed, as well as the fact that parties may provide for the redetermination of participation formulas once a certain number of development wells have been drilled – the execution of all of which is subject to previously obtaining the Ministry's authorisation.

A unitisation agreement or order will not imply the transfer, exchange or modification of interest owners' participation in their respective blocks.

The Ministry of Energy may authorise the incorporation into the unit of areas that are not yet subject to any E&P contract or entitlement, without prejudice to the State's ability to award that area later on to a third party.

When a common reservoir is located under blocks in different exploratory, appraisal or development terms, the Ministry may authorise the extension of the applicable term in order to align the relevant contractors' operations.

The Ministry of Energy may consult an internationally renowned third-party expert during the unitisation process when interest owners do not submit information or fail to reach an agreement.

A Surveillance Committee, comprised of members designated by the interest owners of the unitised field, must supervise the unit operators' activities.

The parties to a unitisation agreement may stipulate any dispute resolution mechanism of their choice, including submitting their disputes to a third-party expert.

An interest owner may request the termination of a unit by proving that the unit does not produce oil or gas revenues exceeding operating costs or that unit operations are unfeasible.

The unitisation of reservoirs traversing the U.S.-Mexico border must be conducted in accordance with the Agreement between the United States and Mexico Concerning Transboundary Hydrocarbon Reservoirs in the Gulf of Mexico.

Assignment of Interests in E&P Contracts

The E&P contracts awarded by CNH provide that the sale, assignment, transfer or encumbrance of any rights thereunder are subject to CNH's prior authorisation. E&P contractors (except for those whose shares are publicly traded) are even required to ensure that they do not suffer a change of control without CNH's prior authorisation. Changes that do not imply a change of control may simply be notified to CNH.

On 30th January 2017, CNH issued guidelines regarding the authorisation procedure which E&P contractors and operators must follow prior to effecting a change of control. The procedure is meant for CNH to verify that the minimum technical, financial and operational capabilities, and experience, required from E&P contractors and operators under the relevant bidding procedure are not circumvented as a result of the change of control.

State-appointed Trader

On 16th November 2017, CNH commenced a government procurement procedure to hire a trading company to market the State's share of oil and gas originating from production sharing contracts. The State's trader must transfer the sale proceeds to the

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Mexican Oil Fund, after subtracting the trader's fees and, where applicable, logistics costs. The contract to be awarded has a three-year term starting as of 1st January 2018.

Currently, Pemex's trading arm, PMI Comercio Internacional, is acting as the State's trader.

Natural Gas

Mexico has also continued the gradual implementation of a competitive natural gas transportation and trading market, which should be completely liberalised by 2018. The Mexican Energy Regulatory Commission ("CRE") estimates that more than US$12 billion will be invested in natural gas transportation, distribution and storage projects in Mexico in the next five years.

In 2015, Mexico increased its volumetric net natural gas pipeline imports by almost 50% (the largest increase worldwide). This is a result of Mexico's plan to increase gas imports from the south of Texas to Mexico's combined-cycle power plants and manufacturing hubs. Mexico is building 5,000 km of gas pipelines in order for its network to reach 21,000 km by 2019.

CRE will apply asymmetric regulations to Pemex until the creation of a multiple-player, efficient and competitive market has been completed. During the transition period, CRE will continue regulating the terms and conditions of Pemex's first sales.

In February 2017, CENAGAS, the new independent operator of the Mexican gas network, conducted its first annual auction of import pipeline capacity. BP won an aggregate 200 billion Btu/D capacity in two pipelines.

Effective 1st July 2017, CRE eliminated the cap on Pemex's natural gas first sale prices and launched the Permanent Reserve Capacity Regime. Natural gas prices are now set by the market. As a result, it is expected that Pemex's production of natural gas increases, and that the new E&P contractors start offering their production soon. The Permanent Reserve Capacity Regime will allow users to reserve capacity in the gas pipeline network through open season processes organised by CENAGAS.

Gasoline and Diesel

The Mexican gasoline and diesel market is also undergoing a liberalisation process. Since 1st January 2016, retailers may sell gasoline and diesel under their own brands or brands licensed from private companies rather than Pemex. More than 11 gas station brands are now present in the market. Since 1st April 2016, any company may obtain an import permit. As a consequence, 16 companies are already importing gasoline and 23 are importing diesel. Over the course of 2017 maximum retail gasoline and diesel prices were phased out on a geographical basis. Since 30th November 2017, all Mexican retailers may sell at market prices.

In November 2017, the Ministry of Energy published a public policy imposing minimum inventory requirements for holders of fuel marketing and distribution permits who sell gasoline, diesel and aviation fuel to service stations and final users. The minimum fuel storage requirements will start to apply in 2020 and aim at raising minimum inventories from five days of sales to 10–15 days of sales in 2025.

Canada

The situation in Canada continues to be somewhat in a state of flux due to regulatory, political, physical and commercial issues. At both the provincial and federal levels, legislatures and regulators are imposing increased environmental controls and taxation on energy-related activities. For example, a new Canadian federal Pipeline Safety Act came into force on 19th June 2016. The Act increases the regulation of pipelines and the liability of pipeline operators. In addition, First Nations (Indigenous) bands are politically powerful in western Canada and, in many cases, new energy projects must be approved by First Nations bands having traditional rights over the land and rights-of-way to be used for these projects.

As if regulatory and political constraints were not enough, the terrain through which pipelines must pass – from the oil and gas fields of British Columbia and Alberta for export through British Columbia ports – presents extremely expensive construction challenges. In addition, the overall costs of proposed western Canadian LNG projects are increasing to a point where they may not be competitive with energy supplies from other markets, leaving open the question of whether any of the approximately 20 announced West Coast LNG export projects will ever be built.

After nine years of controversy, on 24th March 2017, the Trump Administration in the United States approved the Keystone XL oil sands pipeline from Alberta to the United States. This action overturned the Obama Administration's previous rejection of the pipeline on the grounds that the project was not in the national interest of the United States and would undermine U.S. global leadership in fighting climate change. Controversy over the pipeline continues however. Commencement of construction of major sections of the pipeline could remain tied up in the courts for several more years. In addition, questions have been raised as to whether demand for the pipeline's capacity is sufficient to justify its completion.

Meanwhile, on 5th October 2017, TransCanada announced that it would no longer be proceeding with its long-planned Energy East project, a major eastward-bound pipeline system. The pipeline had faced its own set of hurdles, not the least of which were Ontario and Quebec provincial environmental protections and spill response plans.

United States

Several important developments have recently occurred on the United States energy front relating to the environment, local regulation of energy resources, energy exports and the general impact of the Trump Administration on energy issues. In addition, Hurricane Harvey, which caused extensive flooding in the refining and petrochemical centres of the U.S. Gulf Coast in August of 2017, affected production and pricing of petroleum and petrochemical products.

Environmental

On 2nd June 2014, under the Obama Administration, the Environmental Protection Agency ("EPA") announced a proposed rule that would cut carbon emissions by 30% in the U.S. by 2030. A 2014 U.S. Supreme Court case, *EPA v. EME Homer City Generation*, upheld the EPA's power to impose interstate pollution controls. The decision turned on the EPA's interpretation of the word "significant", which the agency said could mean more than one thing. The court agreed.

However, environmental activism under the Obama Administration is being reversed under the Trump Administration. As of the time of writing, since January 2017, when Donald Trump took office, over 50 environmental rules have been overturned, are in the process of being rolled back or are being seriously considered for roll-back. For example, in October 2017, the EPA proposed a repeal of the Obama Administration's Power Plan. Proposals such as these have

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been met with strong opposition from environmental groups and several State governments and will likely end up in litigation.

Municipal Activism Against Energy Resource Development

Courts in some States are upholding local authority to limit upstream energy developments, pursuant to zoning or home rule provisions. The energy industry has fought back, arguing that these regulations limit their capability to do business within the boundaries of a State, infringe private property rights, and create an unreasonable "patchwork" of inconsistent regulation, thereby increasing the costs of their operations and making the development of energy resources unnecessarily inefficient.

Following a New York court's decision on zoning laws banning oil and gas production, where the court held that the State-wide Oil, Gas and Solution Mining Law does not preempt the authority vested in municipalities to regulate land use, the Supreme Court of Pennsylvania in July 2014 invalidated part of the commonwealth's 2012 revised oil and gas law, known as Act 13. The Pennsylvania's Supreme Court's decision affected Pennsylvania's Public Utility Commission's ability to review local drilling ordinances to determine if they comply with the law, and the ability of the industry to appeal zoning decisions in the Commonwealth Court. Pursuant to this judicial decision, any challenges regarding zoning decisions would have to start in a county court. The decision affects one of the fundamental purposes of Act 13; that is, to provide consistency to the challenges of local ordinances.

In other sectors of the energy industry, municipal action is also gaining ground. In July 2014, in Maine, the City Council of South Portland approved zoning changes that will prohibit the export and bulk loading of Canadian crude onto marine tank vessels from the city's waterfront. In Wisconsin, landowners and municipalities have been fighting a battle against the State and wind energy industries, arguing for greater local control, citing the harmful effects of windmills, including aesthetic and health concerns.

In November 2014, the City of Denton, Texas enacted a ban on oil and gas drilling by hydraulic fracturing. In reaction, on 18th May 2015, the Texas Governor signed into law a bill that diluted the authority of local governments to ban drilling operations. The law recognises the right of owners to exploit their mineral resources "fully and effectively", but the power is not absolute. Local governments still have the right to regulate activities for the purpose of health and safety.

Exports

In December 2015, the 40-year general ban on crude oil exports from the United States was lifted. By August 2017, the U.S. was exporting an average of 772,000 barrels per day of crude oil. In light of the shale boom, the light, sweet crude derived from shale formations, which is not well-suited for the U.S. Gulf Coast refineries, represents a particularly attractive commodity to export.

Legislation

In the summer of 2016, the United States Senate passed an almost 800-page bill dealing with many aspects of energy, called the Energy Policy Modernization Act. One of the more significant provisions of the bill dealt with improving the procedures for the export of domestically produced natural gas by way of ELNG. The bill fell just short of passage in a bicameral Congressional conference at the end of 2016. A new bill, the Energy and Natural Resources Act, was introduced in 2017. It builds on the Energy Policy Modernization Act, addressing a wide range of issues. It features 11 titles on the following topics: efficiency; infrastructure; supply; accountability; conservation; federal land management; National Park System management; sportsmen's issues; water infrastructure; natural hazards; and Indian energy.

Election of Donald Trump

In view of the election of Donald Trump as President, a regulatory environment friendlier to the energy industry can be expected, but the details are yet to be worked out and vocal opposition to many initiatives of the new administration can be expected. With its "America First Energy Plan", the Trump Administration has created an environment that many consider very friendly to the oil and gas industry. Regulations have been aggressively rolled back and goals of "energy independence" and "energy dominance" have been set. Changes have been implemented very quickly and more can be expected, causing some in the industry to become concerned about uncertainty and the impact on oil industry decision-making. As changes continue to be made, it remains to be seen how they will impact the industry over time. What is certain is that these changes will come with unique challenges.

Conclusion

The dramatic opening of the Mexican energy industry and the new oil and gas supplies available throughout North America through shale reserves, discoveries of new conventional oil fields and the Canadian oil sands, will bring innumerable social and economic benefits to the entire region. Of course, these developments also introduce a dramatic shift in supply/demand models for pricing as well as the need for complicated trade-offs in the areas of environmental and safety protections and taxation. Overall, however, the writers remain optimistic that a proper balance will be maintained for the good of all constituents. Unfortunately, there will be winners and losers as the North American energy drama unfolds but, overall, the region's and the world's economies should ultimately benefit as these developments evolve.

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Stone Pigman Walther Wittmann PLLC has extensive experience assisting clients in all aspects of energy-related transactions, business formations, project financings, M&A, strategic alliances and the purchase and sale of major energy assets. In addition to developing project structures, we often serve as lead counsel on contracts for joint ventures, joint operations, sales and purchases, processing, services, transportation, development, investment, production sharing, farm-out agreements, drilling, storage, construction, operation and management and technology licensing.

We have handled hundreds of domestic and international energy deals that involve the exploration, extraction, processing, transportation and sale of hydrocarbons, renewables and other natural resources. Our clients include small and large entities, major and independent oil companies, drilling companies, oil field service providers, lenders, developers, government agencies and foreign investors.

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Albania

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

The exploration of gas in Albania has its beginning in 1955. The exploitation of gas in Albania for industrial use (chemical residues industry, oil industry and production of electric power) dates back to 1963, when the gas field of Bubullima (Area of Kallm) was first exploited, followed by the gas field of Divjaka in 1964 with a total production of 70 million cubic metres ("**Mcm**")/year, Frakulli in 1972, Finiq-Krane in 1974, Ballaj in 1983, Povelça in 1987 and Delvina in 1989.

The highest production of gas in Albania was registered in 1982 with a total production of 0.937 billion cubic metres ("**Bcm**"), while the cumulative production of natural gas is 3.15 Bcm, and the cumulative production of accompanying gas is 8.7 Bcm. After the 1990s, the production of natural gas decreased to 12 Mcm/year.

Currently, the number of wells producing natural gas is approximately 20, with a minimum production of 200–300 normal cubic metres ("**Nm^3**")/day.

According to the data provided by the National Agency of Natural Resources ("**NANR**"), the geological reserves of natural gas are 18,163,700,000 Nm^3 and lie mainly in the Kuçova and Patos oilfields.

By virtue of Law No. 104/2013, dated 25.03.2013 "On the ratification of the agreement between the Republic of Albania, the Republic of Greece and the Republic of Italy for the project for the Trans Adriatic Pipeline" ("**TAP**"), and Law No. 116/2013, dated 15.04.2013 "On the ratification of the agreement with the government of the hosting country between the Republic of Albania, represented by the Council of Ministers and Trans Adriatik Pipeline Ag, in relation to TAP, as well as the agreement between the Republic of Albania represented by the Council of Ministers and Trans Adriatik Pipeline Ag, in relation to TAP", the Republic of Albania will implement the TAP.

This project will link three countries, namely Greece, Albania and Italy. In January 2010, TAP opened country offices in Greece, Albania and Italy. The implementation of TAP in Albania will develop the natural gas sector in Albania. According to studies, the consumption of natural gas is predicted to increase to 1.6 billion m^3 in 2030, of which approximately 70% is expected to be used for the production of electric power. Initially, the natural gas shall be used in the industry sector for the production of electric power, whereas after the year 2020, the gas shall be provided to domestic consumers with an expected final consumption of 37% in 2030.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Currently, Albania's energy requirements are not met using natural gas due to the lack of infrastructure. By virtue of the data provided by the Institute of Statistics ("**INSTAT**"), the production of natural gas in Albania for the year 2015 was 30 kilotons of oil equivalent ("**ktoe**"), while the quantity distributed to the consumer was only 12 ktoe. However, the consumable produced quantities are used in the industry sector, while the energy requirements in Albania are mainly met by other sources such as crude oil, coal, firewood and electric power.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Albania's natural gas requirements are not met through domestic natural gas production. According to the data provided by INSTAT, the production of natural gas in Albania for the year 2015 was 0.11 ktoe/10,000 habitants, while the quantity distributed to the consumer was only 0.04 ktoe/10,000 habitants. Currently, the produced quantities of natural gas are used only in the industry sector.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

There is no export of natural gas through pipelines due to the lack of infrastructure.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

The oil sector in Albania is regulated by the following:

- Law No. 7746/1993 "On hydrocarbons – (exploration and production)" ("**Law 7746/1993**");

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- Law No. 9876/2008 "On the production, transport and trade of bio fuels and other fuels, renewable, for transport, as amended" ("**Law 9876/2008**");
- Law No. 8450/1999 "On the processing, transport and trading of oil, gas and their by-products" ("**Law 8450/1999**");
- Law No. 8561/1999 "On the expropriation and temporary taking over of private property for public interest" ("**Law 8561/1999**"); and
- Law No. 7811/1994 "On the approval of the Decree No. 782/1994 'On the fiscal regime in the hydrocarbons sector (exploration and production)'" ("**Law 7811/1994**").

The first efforts towards oil exploration in Albania started in 1800, and were intensified in 1900 in cooperation with the international oil industry. The research of oil in Albania started in 1918, when Leo Madalena (an Italian geologist) discovered the first oilfield in Drashovica (Vlora).

Since then, 10 (ten) oilfields have been discovered in Patos in 1927, Kuçova in 1928, Marinza in 1957, Visoka in 1963, Gourisht-Koçul in 1965, Ballsh-Hekal in 1966, Finiq-Krane in 1973, Çakrran-Mollaj in 1977, Delvinë in 1989, and Sqepur in 2001.

The production of oil in Albania started in 1929 with a production of 750 tons of oil. In over 85 years of exploitation, Albanian offshore oilfields have produced 56,249,677 tons of crude oil.

According to the data provided by NANR, in 2014 1.4 million tons of oil was produced and in 2015 1,273,728 tons of oil was produced; 1,226,154 tons of that oil was produced based on agreements concluded with foreign companies and the rest was produced by the State-owned company Albpetrol.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Albania's energy requirements are not met using oil, but mainly by the production of electric power. By virtue of the preliminary data provided by INSTAT, the production of oil in Albania for the year 2015 was 1,279 ktoe, while the quantity distributed to the consumer was 1,160 ktoe.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

According to the data provided by INSTAT, the production of oil in Albania for the year 2015 was 4.43 ktoe/10,000 habitants, while the quantity distributed to the consumer was 4.01 ktoe/10,000 habitants. Based on the data provided by NANR, 243,553 tons of crude oil was distributed in the internal market until August 2017.

2.4 To what extent is your jurisdiction's oil production exported?

According to the data provided by NANR, in 2017 (until August 2017), 590,985 tons of crude oil was produced, 319,350 tons of that crude oil was exported. Based on the data provided by the Albanian customs, the principal countries where Albanian oil is exported to are Italy, Spain and Malta.

As per the data provided by INSTAT, the export of oil for the first quarter of 2015 was 154 million litres, which has decreased compared with the same period in 2014, when the amount exported oil was 276 million litres. The income for the first quarter of 2015 amounted to 4.9 billion Albanian Lek ("**ALL**") (approx. 35,612,392 Euros), whilst in the first quarter of 2014 the income from the export of oil amounted to 15.2 billion ALL (approx. 110,369,692 Euros).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The oil and natural gas sector in Albania is regulated by all the laws mentioned in question 2.1, as well as: Law No. 102/2015 "On the natural gas sector"("**Law 102/2015**"); DCM 848/2016 "On the establishment of the company "Albgaz" Sh.a. and determination of the public authority representing the state as shareholder of the company "Albpetrol" sh.a. and "Albgaz" Sh.a. (**DCM 848/2016**); and the Regulation on Licensing, Amendment, Partial or Integral Transfer, Withdrawal and Renewal of Licences in the Gas Sector, as approved by the Albanian Energy Regulator Authority ("**ERA**") with Decision No. 9, dated 11.02.2011 ("**Regulation 9/2011**").

By virtue of Albanian law, all petroleum in its natural state is the exclusive property of the Albanian State, represented by the Ministry of Infrastructure and Energy (the "**MIE**"). The MIE is entitled to conclude petroleum agreements with any contractor interested in the research and production of oil and gas, granting them the right to research and produce as per the terms and conditions of the petroleum in the relevant contract area.

NANR is an institution dependent on the MIE. NANR is entitled to negotiate petroleum agreements, prepare the necessary documentation and practices concerning the granting of the permits, licences and authorisations in compliance with the law which enables an applicant to enter into agreements and to perform petroleum operations.

Albpetrol Sh.A. ("**Albpetrol**") is a State-owned company, having as its object the production and trade of petroleum products based on the petroleum agreement concluded with the MIE on 26.07.1993 "On the authorization for the performance of Petroleum Operations", and having the right to grant to third parties a licence agreement for the areas under its administration.

Albgaz Sh.A ("**Albgaz**") is a State-owned company, operating as a combined operator performing the activity of the Transmission System Operator and Distribution System Operator of natural gas.

The ERA is the regulatory authority in the sector of natural gas and electric power, with the exception of the exploration and production/exploitation of natural gas.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The State mineral rights to develop oil and natural gas are transferred to an investor by entering into a petroleum agreement with the latter. The petroleum agreement may be for a term of up to five years for exploration, and up to 25 years for production and exploitation of the hydrocarbon reserves.

The petroleum agreement may provide to the investor the right to construct and operate pipelines in Albania, the right to own part of the production and the right to sell and export the production.

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Any interested party wishing to enter into a petroleum agreement on hydrocarbons should submit an application to NANR, and the latter must submit to the MIE the necessary documents. The MIE decides on the approval or refusal within 10 days, and, in case of approval, NANR starts the negotiation on the terms and conditions of the petroleum agreement with the applicant.

The final draft may be sent for review to the Ministry of Finance and to the Ministry of Justice. The MIE should sign the petroleum agreement within 10 days of receiving the revised and renegotiated agreement, and send it to the Council of Ministers for final approval.

Even in case of a licence agreement to be entered into with Albpetrol for the areas administered by the latter, the negotiation should be undertaken with NANR, and the licence agreement must be signed by the MIE and Albpetrol, and finally the agreement should be approved by the Council of Ministers.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Any legal entity wishing to perform exploration activity in relation to oil and natural gas should enter into a petroleum agreement with the MIE or into a licence agreement with Albpetrol for areas under the operation of the latter. The exploration agreement may be entered into for a period of five to seven years.

Any legal entity wishing to perform production and exploitation activity in relation to oil and natural gas should enter into a petroleum agreement with the MIE or into a licence agreement with Albpetrol for areas under the administration/operation of the latter. The production and exploitation agreement may be entered into for a period of 25 years and renewed for a period of not more than five years.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

All oil and natural gas in their natural state are the exclusive property of the Albanian State. The latter may delegate the right to explore, produce and exploit to any interested third party by entering into a petroleum agreement or licence agreement. In such agreement, the Albanian State is represented by the MIE, while the implementation of such agreement is supervised by NANR.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The following taxes are applicable:

- Profit tax amounting to 50% of the net profit for the relevant fiscal year, payable according to the relevant petroleum agreement.
- Royalty tax on oil and gas amounting to 10% of the sales, payable not later than the 15th day of the following month.
- Bonuses paid for entering in a concession agreement, as stipulated in the respective agreement.
- Share of the production of oil and gas, as stipulated in the respective agreement.

In case of a production-sharing agreement, the contractor is entitled to compensate the State authority in oil or natural gas as compensation for business costs.

3.6 Are there any restrictions on the export of production?

There are no restrictions in relation to the export of oil and natural gas. Limitations may be imposed by the petroleum agreement to supply or contribute to the supply of the internal market in case of an emergency.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are no currency exchange restrictions or restrictions on the transfer of funds derived from production out of the jurisdiction.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The oil and natural gas development rights may be transferred or assigned to any third party depending on the provisions of the petroleum agreement with the MIE.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Any operator wishing to operate in the oil and natural gas sector, in order to enter into an exploration or exploitation agreement, should have necessary financial means proving the ability to undertake such activity. There is no specification on what kind of security or guarantee should be provided; however, in practice, a bank guarantee is required.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The rights to develop oil and natural gas may not be pledged.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

In addition to the authorisation mentioned in question 3.3, the following permits are required:

- The Environmental Permit approved by the Minister of Environment and issued by the National Licensing Center.
- The Development Permit, Construction Permit and Use Permit issued by the National Territory Council.
- The exploration and production of hydrocarbons may be performed by experts equipped with a professional permit for such activity. This does not apply to foreign experts who perform such activity for not more than 12 months as of their entry into Albanian territory.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

There is no specific law or regulation on the abandonment or

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decommissioning of physical structures used in oil and natural gas development. However, the holder of an oil and natural gas development right should take all necessary measures for the protection of the environment and diminution of the pollution due to the performance of petroleum operations.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/ requirements of the legislation?

Gas storage is regulated by Law No. 102/2015. Gas storage may be performed by any legal entity duly licensed by ERA. The licence is granted for a period of not more than 30 years and may be renewed. Depending on the efficiency and profitability, ERA may license one or more operators.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

By virtue of Law No. 102/2015, only legal entities duly licensed by ERA may perform wholesale and retail of natural gas (including LNG). Such licence is issued for a period of not more than 10 years and may be renewed.

The price in relation to wholesale and retail sale of gas is determined based on supply and demand.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

There are no specific requirements, limitations or rules in relation to cross-border sales of oil and oil products. Any legal entity duly licensed may perform the import/export of oil and oil products in accordance with the international convention ratified by the Albanian government.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Recently, the Albanian Parliament approved Law No. 102/2015, which implements Directive 2009/73/EC of the European Parliament and of the Council of 13.07.2009 concerning common rules for the internal market in natural gas, and governs the transport and associated infrastructure in relation to natural gas.

The construction and use of pipelines for the transmission and distribution of natural gas, LNG and natural gas deposits, direct lines connecting the Albanian natural gas system with neighbouring systems, as well as any plant, installation or other device incorporated in the natural gas sector, is subject to approval by the Council of Ministers. Such approval is granted for a period of 30 years, renewable.

Any legal person wishing to operate in the natural gas sector and to perform the following activities should obtain a licence issued by ERA for the transmission, distribution, supply and trade of natural gas, as well as operation of natural gas storage facilities and LNG facilities.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The following permits and authorisations are required for the construction and operation of the natural gas transportation pipelines and associated infrastructure:

- The Environmental Permit approved by the Minister of Environment, issued by the National Licensing Council ("**NLC**").
- The approval of the Council of Ministers on the construction and use of the natural gas transportation pipelines and associated infrastructure.
- The Development Permit, Construction Permit and Use Permit issued by the National Territory Council.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

An investor who has entered into a petroleum agreement, or a holder of the permit to construct natural gas transportation pipelines, is also granted the right of use of the land. The right to use the land is exercised by virtue of an agreement entered into with the landlord, being between the State entity, local government or private person owning the immovable property and the investor/holder of the permit, against the payment of a fee. The investor shall compensate the landlord for all the damages suffered by the latter due to such construction works, installment of infrastructure, or the limitation to use the land.

In case the landlord fails to enter into such an agreement with the investor, the latter is entitled to address the competent court for the purpose of determining the easement rights and the annual payment which is due to the landlord.

Furthermore, Albanian law provides for the expropriation of private property, provided that the oil and natural gas activity in a certain area is of special public interest and is the object of dispute between the investor and the landlord in relation to use of the relevant property.

The expropriation right is exercised for a public interest that cannot be completed or protected by other means, only on the grounds set out in Law No. 8561/1999 and against fair compensation.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

The Transmission System Operator ("**TSO**"), in the capacity of the administrator of natural gas transportation infrastructure, should ensure unlimited access to the transmission system to any third party in accordance with the terms and conditions determined in the Network Transmission Code, approved by ERA. Access for third parties may be granted, provided that the operator has the necessary financial and professional capacity to exercise the access right.

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The access right to the natural gas transportation pipelines is regulated by virtue of an agreement entered into with the TSO. The terms and condition of the access agreement as well as the access fees should be in compliance with the methodology approved by ERA.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

To date, the oil transportation system is not integrated or interconnected with any transportation system of any third country.

Upon completion of the TAP Project, it is expected that the natural gas transportation pipelines in Albania will be integrated and interconnected with the Greek and Italian natural gas transportation systems.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

The TSO may refuse third-party access to the natural gas transportation pipeline or associated infrastructure due to lack of capacity, in case such access impairs the performance of obligations to public service.

In such case, TSO should make the necessary improvements to the infrastructure, to the extent it is suitable from a financial point of view, or in case the interested third party is willing to pay for such improvements.

However, the proposed Transmission Network Code which regulates, *inter alia*, the terms and conditions for providing access to third parties, is expected to be approved by ERA.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

In relation to oil, the parties are free to agree the terms and conditions of transport by entering into an agreement, which should then be filed with NANR.

In relation to the transport of natural gas, the terms and conditions, as well as tariffs, are regulated in accordance with the proposed methodology which is expected to be approved by ERA.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The transmission and distribution of natural gas is regulated by Law No. 102/2015 and Regulation 9/2011.

Transmission means the transport of natural gas to the client through a network of high-pressure pipelines, which are different from the pipelines in the exploration-production system and the distribution pipelines, excluding the service of supply. Natural gas transmission is an activity of public interest and may be performed by a TSO licensed by ERA. A TSO is a legal entity that operates only in the transmission of natural gas and has, *inter alia*, the following powers: to construct, own, operate, maintain and develop a safe, efficient system for natural gas transmission and ensure a competitive market, as well as ensure sufficient capacity to meet reasonable demand for the transmission of natural gas; to provide a natural gas transmission service; and to grant third-party access to the transmission system in accordance with the Transmission Network Code.

Distribution means the transport of natural gas through a pipeline network to the client, excluding the service of supply. The distribution of natural gas may be performed by a distribution system operator ("**DSO**"). A DSO is a legal entity that operates only in the distribution of natural gas and has, *inter alia*, the following powers: to construct, own, operate, maintain and develop a safe, efficient and environmentally friendly system for natural gas distribution; to provide a stable and efficient distribution of natural gas in accordance with licence conditions; and to grant third-party access to the transmission system in accordance with the Distribution Network Code.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

The governmental authorisations required to operate a distribution network are:

- The Approval of the Council of Ministers on the construction and use of a distribution network.
- The Distribution Licence issued by ERA.
- The Environmental Permit approved by the Minister of the Environment and issued by the NLC.
- The Development Permit, Construction Permit and Use Permit issued by the National Territory Council in case of construction of infrastructure.

7.3 How is access to the natural gas distribution network organised?

The DSO provides access to the distribution system, within the limits of distribution capabilities and technical regulations, in accordance with the terms and conditions stipulated in the Distribution Network Code, approved by ERA.

The DSO should publish the terms and conditions approved by ERA, including rules, guarantees and access fees. The same terms apply to all customers without discrimination.

The DSO should grant access to the natural gas distribution network taking into consideration the financial ability of the third party. However, all the criteria for granting access should be non-discriminatory, proportional and transparent.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Law No. 102/2015 does not provide for the right of ERA to require a DSO to grant capacity or expand its system in order to accommodate new customers. However, the Distribution Network Code, regulating, *inter alia*, the terms and conditions for providing third-party access, is expected to be approved by ERA.

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7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The access fee should be calculated in accordance with the methodology approved and published by ERA.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

The licence or assets forming part of the distribution system may be transferred entirely or partially to any third party upon prior approval of ERA, with the exception of assets having a minimal value or those not related to the licensed activity. In case of transfer of assets, the transferee should apply to ERA to obtain a new licence.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

The wholesale and retail of natural gas may be performed by a legal entity duly licensed by ERA. A company licensed for the supply of natural gas is also entitled to perform the trading of natural gas, provided that separate accounts are kept of each of the activities.

ERA surveys the natural gas market in cooperation with the Competition Authority at least every two years, and the Competition Authority takes measures to ensure effective competition in the natural gas market and to identify market abuse cases.

A regulation on the organisation and functionality of the natural gas market is expected to be approved by ERA.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

There are no specific provisions on tradable natural gas commodities. However, by virtue of Law No. 102/2015, natural gas comprises methane, including any associated gas, and all hydrocarbons in a gaseous state in normal atmospheric conditions, including LNG, biogas or other types of gas transmitted and distributed in the pipeline system.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

The operation of LNG facilities is regulated by Law No. 102/2015. The LNG system may be operated by any legal entity licensed by ERA, and depending on the efficacy, by one or more operators.

The LNG system operator has, *inter alia*, the following powers: to operate, maintain and develop safe, reliable and efficient LNG facilities; to connect the LNG facilities with the transmission system in accordance with the technical rules related to LNG plants; install measurement equipment for inflows and outflows, as well as gas quality parameters; and to ensure objective, equal and comprehensible conditions of access to LNG facilities.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The following governmental authorisations are required in order to construct and operate LNG facilities:

- The Approval of the Council of Ministers on the construction and use of LNG facilities.
- The LNG facilities operation licence issued by ERA.
- The Environmental Permit approved by the Minister of Environment and issued by the NLC.
- The Development Permit, Construction Permit and Use Permit issued by the National Territory Council.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The fee for accessing LNG facilities is calculated in accordance with the methodology expected to be approved and published by ERA.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

The LNG system operator should offer services on a non-discriminatory basis to all network users that comply with the market requirements.

An LNG system operator may refuse access to a third party to LNG facilities or associated infrastructure due to lack of capacity, in case such access impairs the performance of obligations to public service.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

In addition to the laws indicated in question 2.1, the downstream oil sector is regulated, *inter alia*, by the following:

- DCM 755/2014 "On the determination of procedures and requirements with regard to the award of a 'Processing Licence' for processing plants of the by-products of oil".
- DCM 19/2015 "On the procedures and requirements with regard to the granting, transfer and renewal of the concession licence for refineries for crude oil processing activity for the production of the by-products thereof".
- DCM 970/2015 "On the determination of the procedures and requirements for granting licences for the trading of crude oil and its byproducts".
- Order of the Ministry of Energy and Industry 389/2014 "On the data that should be sent by legal entities exercising their activity in the sector for processing, transporting and trading crude oil and its by-products".
- Order of the Ministry of Energy and Industry 315/2017 "On the procedures for issuing technical certification for the entities carrying out activities in the sector of processing, transport and trading crude oil and its by-products".

A legal entity may operate an oil refinery for processing crude oil, provided that it is established as a joint stock company and after obtaining a concessionary licence through a decision of the Council of Ministers for a term of 30 years, renewable.

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Processing plants are entitled to carry out the activity of processing petroleum by-products, provided that it is established as a joint stock company and has obtained the processing licence, issued by the Ministry of Energy and Industry, which is issued for a period of 15 years, renewable.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The wholesale of oil may be performed by any legal entity established as a joint stock company, provided it has obtained a trade permit from the Ministry of Energy and Industry for a period of 10 years, renewable.

In addition to the above, the wholesale of oil may be performed by (i) legal entities producing hydrocarbons, the latter being entitled to sell the produced crude oil only to oil refineries for export purposes, and to companies that have obtained a trade licence for crude oil, (ii) oil refineries, which may trade their own production, and (iii) processing plants, which may trade their own production.

Albanian law does not impose any restriction as to the ownership of such companies.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The competent authority responsible for the regulation of competitive and anti-competitive practices in both the oil and gas sectors is the Competition Authority ("**CA**").

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

By virtue of Law No. 9121/2003 "On the protection of competition", the following are considered anti-competitive conducts that might restrict or distort competition: prohibited agreements; abuse of dominant position; and concentrations.

Prohibited agreements, specifically, are agreements that: directly or indirectly fix purchase or selling prices or any other trading condition; limit or control production, markets, technical development or investment; share markets or sources of supply; provide dissimilar conditions to equivalent transactions with different parties, thereby placing them at a competitive disadvantage; and render the conclusion of agreements subject to acceptance by other contracting parties of additional obligations that, due to their nature or commercial use, are not related to the object of such agreements.

The abuse of dominant position may occur in the following cases: the direct or indirect fixing of unfair selling or purchase prices or other unfair trading conditions; the restriction of production, markets or technical development; the provision of dissimilar conditions to equivalent transactions with different parties, thereby placing them at a competitive disadvantage; and render the conclusion of agreements subject to the acceptance by other contracting parties of additional obligations that, due to their nature or commercial use, are not related to the object of such agreements.

The concentration may occur in the following cases: the merger of two or more companies; the acquisition of direct or indirect control by one or more individuals or legal entities that simultaneously control at least one other company; and direct or indirect control over one or more companies or parts thereof.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

In case of doubt for anti-competitive actions, the CA, on its own initiative, is entitled to carry out investigations within the premises of the companies or group of companies, and the residences of the administrators, directors and other employees of the companies. The Inspectors of the CA are also entitled to obtain information or seize objects when such seizure is deemed necessary.

Moreover, the CA, according to the information received, may perform either a preliminary or an in-depth investigation. Depending on the results of such investigation, the CA applies the respective measures provided for in the Law "On the protection of competition".

In case of anti-competitive conduct, the CA may impose penalties amounting to up to 10% of the turnover of the previous fiscal year.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Concentrations are considered as such and need to be approved by the CA in case during the year previous to the transaction: (a) the combined worldwide turnover of all participating companies is more than 7 billion ALL (approx. 50 million Euros) and the domestic Albanian turnover of at least one participating company is more than 200 million ALL (approx. 1.4 million Euros); or (b) the combined domestic turnover of all participating companies is more than 400 million ALL (approx. 2.9 million Euros) and the domestic turnover of at least one of the participating companies is more than 200 million ALL (approx. 1.4 million Euros).

The above concentrations should be notified to the CA within 30 days of their conclusion, and the latter must approve or refuse it within two months as of receipt of the notification.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There are no restrictions on acquisition of interests by foreign companies. Therefore, the foreign investor may either establish a company or a branch in Albania for purposes of exercising its activity.

There are no restrictions as to the nationality of shareholders of a company.

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12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Albania has ratified the Energy Community Treaty and has become a part of the Energy Community. In light of the above, and the subsequent obligation of applying the *acquis communautaire*, the new legislation on natural gas, namely Law No. 102/2015 "On the natural gas sector" dated 23.09.2015, is completely harmonised with the European legislation in force.

Moreover, in relation to the TAP Project, the Albanian Parliament has ratified the intergovernmental agreement entered into with Italy and Greece.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Any dispute arising from a petroleum agreement in the oil sector is settled in accordance with the provisions of the agreement, and in practice, petroleum agreements also determine an international court of arbitration as the competent authority for resolving such disputes.

With regard to the companies operating in the natural gas sector, the competent authority for the resolution of disputes arising with regard to licensing and the amendment, transfer, revocation or renewal of a licence, is the Albanian Energy Regulator. The decision of the latter authority may be appealed at the Albanian national courts.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

The New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards was ratified by the Albanian Parliament on 09.11.2000 and entered into force on 27.06.2001.

The Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("**ICSID**") was signed and ratified by the Albanian Parliament on 15.10.1991 and entered into force on 14.11.1991.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

The governmental authorities do not benefit from any immunity, and to date there have not been any difficulties with regard to the enforcement of judgments against the governmental authorities.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

Recently, there have been court procedures initiated by one of the companies operating in the Albanian oil sector; however, due to confidentiality we may not provide further details on the case and the company.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

By virtue of DCM 848/2016, a new State-owned company Albgaz Sh.a. has been established and is entitled to operate as a combined operator performing the activity of the Transmission System Operator and Distribution System Operator of natural gas.

By virtue of the recent amendments of Law 7746/1993, which entered into force on 03.03.2017, two new State authorities shall be established namely: the Scientific Institute of Petroleum; and the State Agency responsible for Petroleum.

The Scientific Institute of Petroleum ("**SIP**") is an advisory body entitled to perform studies, analysis, consultancy, as well as to monitor the performance of any petroleum operations for the exploration and production, processing, transportation, storage and trading of petroleum materials and products.

The State Agency Responsible for Petroleum ("**SARP**"), depending on the MIE, is entitled to implement the government policy in the field of hydrocarbons, participate in the negotiation of hydrocarbon agreements, prepare the documentation and practices necessary for the issuance of permits, licences, authorisations required for the hydrocarbon operations, supervise the hydrocarbon activity and follow the implementation of the related hydrocarbon agreements.

The bylaws implementing the above amendment, in relation to the organisation and operation of SIP and SARP, are expected to be approved by the Council of Ministers.

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Angola

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Angola has 11 trillion cubic feet (297 billion cubic metres) of natural gas resources (as per the Angola LNG website). Historically, the majority of natural gas was re-injected into oil fields to help recovery or simply flared off as a by-product of oil operations. As recently as 2011, re-injection and flaring still accounted for 91% of all the natural gas produced in the country. In the last couple of years, natural gas sector regulations focused on the development of the country's first LNG facility in Soyo. The first exportation of LNG took place in June 2013. The LNG plant is reportedly producing well below its capacity of 5.2 million tons per year due to technical problems. The drop in oil prices has led to a decrease in the sector's productivity.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Based on data made available by the United Nations Development Programme, despite being the second-largest economy in Sub-Saharan Africa in terms of GDP, around 37% of Angolans live below the poverty line. In 2011, about 55% of Angola's primary energy consumption consisted of traditional solid biomass and waste. Petroleum occupies second place, representing 33% of the primary energy consumption in 2011. Natural gas, hydroelectricity, nuclear and other renewable energies still occupy a small percentage of Angola's primary energy consumption.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

The development of the natural gas market is headed by Angola LNG. There is no official Government information about natural gas imports. It is expected that about 20% to 30% of the country's energy needs, consumed primarily by the industrial sector, are to be produced by the Angola LNG Project.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

According to the 2017 *Annual Statistical Bulletin of the Organization of the Petroleum Exporting Countries*, Angola's natural gas exports has grown steadily in the past few years, and correspond to 1.149 million cubic metres. Information on exports to each country is not available.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Angola holds almost 9.5 billion barrels of proved crude oil reserves, according to the latest estimates from the 2017 *Annual Statistical Bulletin of the Organization of the Petroleum Exporting Countries*. Angola is the second-largest oil producer in Sub-Saharan Africa, behind Nigeria. Exploration and production activities related to oil and natural gas in Angola are governed by Act 10/04 of 12 November ("Petroleum Act" or "Act 10/04") and Presidential Decree 211/15 of 2 December ("Presidential Decree 211/15"). The right to produce and explore for oil or natural gas is granted by a concession agreement, generally preceded by a public tender procedure. A concession for exploration and production, after the public tender procedure, is granted by a concession decree, issued by the Angolan Government, attributing to the national concessionaire Sonangol (the exclusive concessionaire for mining rights in Angola) the right to develop a specific oil concession.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

In 2016, according to the 2017 *Annual Statistical Bulletin of the Organization of the Petroleum Exporting Countries*, Angola produced 1.7 million barrels per day of crude oil. Angola's oil production grew by an annual average of more than 15% from 2002 to 2008 as production started from multiple deep-water fields that were discovered in the 1990s. Angola consumed roughly 94,000 barrels per day of petroleum products in 2012, almost double the volume consumed a decade ago. Domestic demand for petroleum remains low due to low levels of economic development. According to a June 2013 International Monetary Fund report, Angola's fuel-subsidy costs are estimated to be the highest in Sub-Saharan Africa, estimated at about 5% of GDP in 2012, equivalent to half of total capital spending.

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2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Angola imports more than half of the petroleum it consumes, particularly refined products. Angola's production has been stagnant as a result of persistent technical problems related to water injection systems and gas cooling, and floating, production, storage, and offloading (FPSO) units associated with some projects. Rapid reservoir depletion has also resulted in steep decline rates at some fields.

2.4 To what extent is your jurisdiction's oil production exported?

In 2017, Angola exported about 1.7 million barrels per day of crude oil. According to information made available by the Angolan Ministry of Finance, in January 2014, China accounted for 45% of the country's sales (hence it is the biggest customer). According to Sonangol, which reported that India and Taiwan complete the top three biggest customers, India is the second largest client of Angolan oil, with 12% of total exports, followed by Taiwan. The United States of America, once one of the largest customers of petroleum of Angola, now occupies fourth place. The list of buyers also includes South Africa in fifth place, followed by Spain, Brazil, Panama, Malaysia, Japan, Ireland and Italy. In 2015, Angola exported 1.8 million barrels of oil per day. In 2018, Angola may surpass Nigeria to become the largest oil producer in Africa. Nearly all of Angola's oil production is exported, as Angola's domestic refining capacity is limited.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The statutory framework for the exploration and production of oil and natural gas reserves is mainly encompassed in the Petroleum Act. In addition, the other relevant statutes are:

- Law 13/04 of 24 December ("Taxation of Petroleum Activities" or "Act 13/04").
- Act 2/2012 of 13 January ("Angolan Oil and Gas Foreign Exchange Act for the Oil Industry" or "Act 2/2012").
- Act 11/04 of 12 November ("Petroleum Customs Act" or "Act 11/04").
- Presidential Decree 211/15 of 2 December (establishes the framework for the activities involved in the exploration of Development Areas – in Portuguese, "*Áreas de Desenvolvimento*").

Under the 2010 Constitution of Angola, the State is the owner of all national resources within the Angolan jurisdiction. Consequently, all oil fields and gas in: the onshore and offshore areas of Angolan territory; internal waters; territorial sea; exclusive economic zone; and on the continental shelf, belong to the public domain of the Angolan State. Consequently, all mining rights are exclusively assigned to the National Concessionaire. All petroleum deposits in Angola are an integral part of the public domain, Sonangol being the exclusive holder of all mineral rights related to such deposits. The Petroleum Act is also applicable to the development and exploration of natural gas. Thus, the provisions provided by the Petroleum Act are equally enforceable for oil and gas exploration – if the gas exploration is made under the oil field licences.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Under the applicable law, i.e., the Petroleum Act, mineral rights are granted to the National Concessionaire. The National Concessionaire, in order to share its technical knowledge and financial capability, may associate with Angolan or foreign entities of recognised capacity, such association may take the following forms:

(a) Corporation.

(b) Consortium.

(c) Production Sharing Agreements.

(d) Risk services agreements.

The most common type of association with the National Concessionaire is the execution of Production Sharing Agreements.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

According to the Petroleum Act and Decree 1/09 of 27 January ("Angolan Petroleum Operations Regulation" or "Decree 1/09"), petroleum operations (i.e., prospecting, exploration, appraisal, development and production of crude oil and natural gas) can only be exercised under a prospecting licence issued by the Ministry of Petroleum, or pursuant to an oil concession awarded by the Government. As for the prospecting licence, any upstanding domestic or foreign company with the necessary technical and financial capacity may apply to the Ministry of Petroleum for the issuance of a three-year prospecting licence (exceptionally extendable at the request of the licensee) to determine the petroleum potential of a given area. The prospecting licence includes geological, geochemical and geophysical research, and the processing, analysis and interpretation of the acquired data, as well as regional studies and mapping, for the purpose of locating oil and natural gas fields. On the other hand, the development of exploration and production activities can only be performed by private sector companies if they join up with the National Concessionaire, as described under question 3.2 above. These joint activities, undertaken between national or foreign companies of proven competence and technical and financial capacity and the National Concessionaire, are subject to the prior approval of the Government.

The concession covers:

(i) An exploration period comprising prospecting, drilling, well-test activities and evaluation.

(ii) A period for development and production. However, the concession may cover just the development and production period and the Government may assign a concession directly to the National Concessionaire should it wish to carry out petroleum operations in a particular area without having to associate with other entities.

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(iii) The framework (provided by Presidential Decree 211/15) for prospection inside certain special areas (in which oil is very likely to be found), in order to promote the discovery of oil within previously agreed concessions.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Through Act 13/78 of 26 August ("the Petroleum General Activities Law"), the Angolan Government has enacted the fundamental principles regulating the exploration of Angola's petroleum potential. As mentioned above, the mineral rights in Angola are owned by the State, the public ownership of all rights and benefits arising from the oil industry being one of the most important governmental aspects.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

According to the available data, until October 2017, the State derived approximately 455 billion Kwanzas from taxes levied to the oil and gas industry. This data does not include the revenues derived from points d) and e) of the list below. Pursuant to Act 13/04, all entities both national and foreign which carry out petroleum operations on national territory are subject to the payment of the following taxes:

a) Petroleum Production Tax.
b) Petroleum Revenue Tax.
c) Petroleum Transaction Tax.
d) Surface Area Charge.
e) Contribution towards the training of Angolan staff.

Additionally, Sonangol is the concessionaire of mining rights in Angola; therefore, it is a part of all Production Sharing Agreements executed in Angola. As a part of all Production Sharing Agreements currently in force in Angola, Sonangol is contractually entitled to receive part of the profits made under the terms and conditions established in each Production Sharing Agreement.

3.6 Are there any restrictions on the export of production?

According to article 8 of Act 11/04, the "exportation of petroleum produced in each petroleum concession, either in its natural state or after having been processed, is exempt from duties and general customs service fee".

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Until 2012, companies operating in the oil and gas sector were subject to the foreign exchange rules set out in their respective concession agreements; however, with the enactment of Act 2/2012, the Government established a general foreign exchange regime applicable to oil and gas activities pursued under the Petroleum Act. As of 1 July 2013, all payments made to such suppliers that are foreign exchange residents under the applicable law must be made through accounts with Angolan banks and in Kwanzas. Foreign investor companies have the right, under said law and after all tax obligations are complied with, to transfer abroad their share of the amounts resulting from the payments of production agreed with the Angolan State.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The assignment of a contractual position in the exploration and production concession agreement requires the prior authorisation of the Ministry of Petroleum, provided that the transferee is of proven competence, and technical and financial capability, unless the assignment is made between subsidiary companies of the transferor. In the event such assignment is authorised, Sonangol has a pre-emption right. If Sonangol does not exercise this right, Angolan companies that are a party to other concession agreements at the time of the transfer are entitled to exercise such pre-emption right.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

A bank guarantee ensuring fulfilment of the work obligations undertaken in prospecting licences and oil concessions is required. In the case of a prospecting licence, the amount of the guarantee shall be 50% of the value of the estimated work. As for the associates of the National Concessionaire, the guarantee shall correspond to the value attributed to the mandatory work schedule of the oil concession. The National Concessionaire may also require its associates to present a parent company guarantee.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The concessionaires of oil refining, storage and transportation of oil-derived products activities cannot freely transfer or encumber the assets pertaining to the concession, such acts being subject to prior authorisation of the grantor.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

According to Law 5/98 of 19 July ("Environmental Law") and to Decree 39/00 of 10 October ("Environmental Protection from Oil Activities Regulation"), all projects to be developed within the scope of the oil and gas sector require the presentation of a number of different reports and studies. The most important report is an Environmental Impact Assessment ("*Avaliação de Impacte Ambiental*" or "AIA"). Angola has ratified the following international treaties related to safety and environmental protection for oil and gas activities:

a) International Convention on Civil Liability for Oil Pollution Damage.
b) International Convention Relating to Intervention on the High Seas in Cases of Oil Pollution Casualties.
c) International Convention on Oil Pollution Preparedness, Response and Co-operation.

Oil field operators are subject to strict rules regarding health and safety (HSE) measures to be taken in order to ensure the quality of life of their employees.

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3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Pursuant to Act 10/04, at least one year prior to the termination of the concession or the date of abandonment of any area included therein, the National Concessionaire shall prepare and deliver to the supervising Ministry a plan providing for the cases of decommissioning the wells, facilities and equipment, and for the rehabilitation of the landscape and continuation of the petroleum operations. The plan shall provide the supervising Ministry with sufficient information in order to assess the future purpose of the facilities from a technical, financial, safety and environmental standpoint.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The main legal framework with regards to gas storage is provided by Act 26/12 and in the recently published Executive Decree 288/14. Please refer to our comments in section 6 below.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Please refer to question 5.1 below.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Activities regarding the import, entry, export and dispatch of petroleum products and crude oil are subject to licensing, as per Act 28/11 ("Oil & Gas Distribution and Commercialisation Act"). Companies in charge of the import/export activities must be controlled by Angolan citizens. The import of petroleum products into the national market is exclusively implemented by the "*Superintendencia Logística do Sistema de Derivados de Petróleo*" (also referred to as "SLSDP"). There are currently no specific rules that apply to cross-border sales or deliveries of natural gas. Such activities are regulated by contract between the parties. An export permit issued by the Ministry of Commerce is, however, required to export natural gas.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

The transportation pipelines and associated infrastructure is regulated by the State. The transportation activities are subject to authorisation from the Ministry of Petroleum. The award of the licence is based on the credibility, experience and competence of the applicant, as well as its financial management and technical capacity for the construction and operation of pipeline facilities in Angola. Operators of oil and gas pipelines have an exclusive right to explore the infrastructures for the transportation of oil and natural gas. The licence authorises its holder to occupy the necessary areas to implement the activities established by the licence. Once the licence is extinct, the assets used in the transportation activity become the property of the State. These assets are the property of the operator during the validity time of the licence. Sonangol is a party to every exploration and production agreement and the Sonangol Group operates as a vertically integrated company that has its main activities focused in all phases of the oil business chain. Its activities include transportation of oil and gas which Sonangol may perform independently or in association with other companies, national or foreign. The transportation of oil and gas must be executed by a company or a consortium, at their own risk, under the authorisation of the Ministry of Petroleum.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

As per Act 28/11, the construction and operation of pipelines is subject to licensing by the Ministry of Petroleum. In order to contract the services of transport via pipeline, the National Concessionaire, its associates and all the other companies have to conduct a tender procedure. The licence can only be granted to legal persons who meet, *inter alia*, the following requirements: (i) technical, logistic and operational capacity; and (ii) economic and financial capacity. In addition, an environmental licence issued by the Ministry of Environment is required. The company or the consortium interested in obtaining pipeline construction rights must have the necessary authorisations issued by the entities competent to grant land rights (please refer to question 6.1 above). The pipeline construction licence is granted for a five-year period by the Ministry of Petroleum and may be extended for one year. The licence to operate pipelines – from the exit flange to the processing facilities, the petrochemical units, or to the export terminal – is granted for a 25-year period by the Ministry of Petroleum and it may be extended one or more times for set periods of time.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

The Executive Power may declare of public interest – for purposes of expropriation and civil easement – the areas required for the construction of pipelines and associated infrastructure. In these cases, holders of land rights must be compensated. The licensee has the right to occupy, under the legislation in force and with respect to existing land rights, the areas necessary for the implementation of the works included under the licence. Please refer to question 6.1 above. Licensed entities may negotiate the land rights with the respective holders and competent real estate and environmental authorities. Pipelines shall be registered with the competent real estate registry office.

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6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Please refer to questions 6.6 and 6.7 below.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

There is no available official data concerning the integrated and interconnected pipeline system.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

The operator of the oil transportation pipeline must transport the crude oil from a third party, with no discrimination and in acceptable commercial terms, provided it has the capacity available in its transport system. The operator cannot impede the expansion of the pipeline, except if the expansion interferes with the technical and operational integrity of the system. However, the entities wishing to expand the pipeline must contribute to the expenses involved. The Ministry of Petroleum may exempt the pipeline licensee/operator from these obligations if it is demonstrated and proved that additional transportation is not possible. The expansion of pipeline capacity may only be effected if:

- It is technically and economically feasible and consistent with safety standards.
- The legitimate interests of the owner or operator are respected.
- The new user does not become the owner of all or part of the pipeline without the consent of the owner or operator.
- The owner or operator is not required to finance part or all of the capacity expansion.

The new user shall be entirely responsible for the capacity expansion costs, including any equipment required for the processing of products of different qualities. If, within six months after the date of commencement of negotiations for expansion of the pipelines' capacity, the parties have not reached an agreement on the commercial and operation terms, this issue shall be submitted to the Ministry of Petroleum for consideration and decision.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Under Act 26/12, the licensee has the right to charge tariffs for the transportation of oil and gas or deny the service for lack of payment of such fees. The tariffs applied shall be approved by the Minister of Petroleum, considering the needs for the operator to recover his investment and obtain profits consistent with the risk.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Two ministries oversee the gas sector: the Ministry of Petroleum, which oversees the exploration and production of oil and natural gas, their refining, distribution and marketing, and the import, export and conservation of petroleum, products and liquefied natural gas; and the Ministry of the Environment, which oversees projects' environmental licensing. Plus, Act 28/11 and Presidential Decree 132/13 of 5 September 2013 ("Activities of Oil Products Sector Act", hereinafter "Decree 132/13") govern distribution of oil products in general (not only natural gas). With the approval of Decree 132/13, the SLSDP was created. The legal ownership, organisational and regulatory framework for natural gas distribution networks is governed by the SLSDP. Also, the Oil Derivatives Regulating Institute (ODRI), created by Decree 132/13, is the Angolan regulatory authority, with management, administrative and financial independence, responsible for regulating the activities of the oil-derived products sector.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Under Act 28/11, the distribution of oil products shall be made by sea, air, inland waterway, road and rail, under the market regime, or through ducts, including networks and extensions of pipelines, under concession. The pipeline distribution is subject to a licence. The licensee operator shall meet the following requirements:

- Technical, economic and financial capacity.
- National energy policy.
- Land-planning and environmental policy.

7.3 How is access to the natural gas distribution network organised?

The distribution network of oil products is under the competition regime. The principles applicable to accessing large storage facilities are also applicable to accessing the distribution network.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

The distribution operators must allow third-party access to facilities, under agreement and following a transparent and objective negotiation. The tariffs shall be published by the distribution operators.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Please refer to the previous question. The tariffs are established under a negotiation process with the distribution operator.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Under the legal system set out in the Petroleum Act, petroleum

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operations – a concept that includes the gas industry – are conducted based on the concession system, which, as opposed to the contractual system, assumes that the operating oil companies obtain a licence or a concession from the State under certain terms and conditions, most of which are established by legislation and some of which are negotiated on a case-by-case basis between the State and the relevant oil companies.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Act 28/11 governs downstream operations of crude oil refining and the storage, transportation, distribution and commercialisation of petroleum products undertaken by refinery operators, storage operators, transportation operators, distribution operators, wholesalers and retailers. Access to such activities is open to all economic agents, who may even exercise several of the abovementioned activities subject to licensing. The trade of oil products may be executed through wholesale and retail traders, as per Act 28/11. The retail trade of natural gas includes the trade and distribution of liquefied petroleum gas ("LPG"), and the trade of LPG bottles. The storage facilities connected to the trade of LPG are subject to licensing under the applicable law. The applicable framework for the licensing of the facilities connected to the trade of LPG is Presidential Decree 173/13 of 30 October ("Decree 173/13"). The facilities connected to the retail trade of LPG bottles are also subject to licensing under the applicable law.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas commodities are usually traded as bundled products in Angola, and there is no specific legislation implementing unbundling procedures for the natural gas industry (in contrast, Presidential Decree 132/13 contains unbundling provisions regarding oil storage and transportation activities).

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

The existing LNG legislation is closely tied with the Angola LNG Project. Its legal regime also includes legislation referring to petroleum activities. According to the legal regime established for the Angola LNG Project, the project shall be executed by Angola LNG Limited, Sociedade Operacional Angola LNG and Sociedade Operadora dos Gasodutos de Angola. Angola LNG Limited will receive revenue generated by the sale of LNG and NGL. The initial shareholders of Angola LNG Limited are Sonangol, Cabinda Gulf Oil Company Limited, Total LNG and BP Exploration (Angola) Limited. The promoter companies may create new companies particularly for the purposes of commercialisation or transportation of LNG or NGL. In such case, the new entities are considered as being independent from Angola LNG Limited, Sociedade Operacional Angola LNG and Sociedade Operadora dos Gasodutos de Angola for all legal and tax purposes. Under the Petroleum Act, Sonangol has exclusive mining rights to gas exploration on the subsoil and continental shelf of Angola, and may associate with both national and foreign private companies in the terms described above. The National Concessionaire is barred from assigning all or part of the mining rights granted and any actions to the contrary are invalid and ineffective. As per the Petroleum Act, the oil fields ("*Jazigos Petrolíferos*") exist within the public domain.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Under Angolan law, natural gas pipeline transportation and storage ancillary to production are treated differently from non-ancillary activities. Ancillary pipeline transportation and storage, with the intention of making natural gas extraction viable, is regulated by the abovementioned rules governing natural gas exploration and production. Non-ancillary transportation and storage, performed in order for natural gas to be commercialised and consumed, is governed by Act 26/12 ("Oil and Gas Transportation and Storage Act"). Natural gas transportation and storage activities are subject to the authorisation of the Ministry of Petroleum, which has the authority to, *inter alia*: (i) approve the construction and expansion of pipelines, supervise the works, and authorise and license the operations; (ii) keep a database concerning pipeline construction and operation; and (iii) define the rules for the granting of pipeline construction and operation licences and oil and gas storage, without prejudicing other authorisations required. The construction and operation of any oil or gas pipeline and storage facilities are subject to a licence issued by the Ministry of Petroleum.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The distribution, associated storage and commercialisation of natural gas and LNG are an essential public service and entail obligations concerning:

i. The safety, continuity and quality of the supply.
ii. Promoting energy efficiency and rational use of resources, as well as environmental protection.
iii. Satisfying the requirements of priority consumers in the areas of health, the armed forces and social assistance.
iv. Consumer protection.

Natural gas is sold as a commodity, its price is set by market forces; the buying and selling of the commodity by market players, based on supply and demand, determines the average price of natural gas.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

As per the Petroleum Act, the Ministry of Petroleum may allow the use of a third party's facilities, if that use contributes to a more efficient use of the existing resources. However, this can only be done if it does not result in a decrease of production levels or ineffective functioning.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream sector commonly refers to the refining of

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petroleum crude oil and the processing and purifying of raw natural gas, as well as the marketing and distribution of products derived from crude oil and natural gas. The processing of oil derivatives and purifying of crude oil is subject to the licensing of the facilities, taking into consideration:

- The technical, economic and financial capacity of the applicant.
- The compliance between the project and national energy policy.
- The land-planning scheme and the goals of environmental policy.

The licence should be granted by the Ministry of Petroleum. The distribution of petroleum products may be carried out:

- Via sea lane, waterway, by air, by road or via railway.
- Through pipeline.

The pipeline distribution is subject to licensing, taking into consideration:

- The technical, economic and financial capacity of the applicant.
- The compliance between the project and national energy policy.
- The land-planning scheme and the goals of environmental policy.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The marketing of oil products is subject to licensing, as per Act 28/11, and may be performed through wholesale or resale trade. The licensee's project shall fulfil the following requirements:

- The technical, economic and financial capacity of the applicant.
- The compliance between the project and national energy policy.
- The land-planning scheme and the goals of environmental policy.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

At present, Angola does not have a general competition law or an anti-trust authority; however, this has become a growing concern and more recent legislation, such as Acts 28/11 and 26/12, reflect the Government's policy to promote consumer protection, equal treatment, and equal opportunities among players in competition. Developments in this area are also expected in light of recent legislation, namely Presidential Decree 68/10 that established that the co-ordination and consistency of revenues and price would be entrusted to the Ministry of Economy and pursued through the Market and Competition Institute ("*Instituto do Mercado e Concorrência*").

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Please refer to question 11.1 above. However, one may occasionally find statutory prohibitions of certain restrictive agreements and practices, in which case such matters would be subject to the governmental body in charge of the respective activity.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

Please refer to our answer to question 11.2 above.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

In addition to rules and restrictions that may be embodied in individual contracts, under the Petroleum Act, transfer of the contractual position held by private companies who are associates of the National Concessionaire ("Associates") to a third party requires the prior authorisation of the Ministry of Petroleum (which will be granted in the form of an executive decree) and the transfer to a third party of a stake or shares representing more than 50% of the Associates' share capital, deemed equivalent to a transfer of contractual position. Such authorisation is not required if the transfer is made to an "affiliate" as defined by law, provided the assignor remains joint and severally liable. We also note that in the case of transfer to a third party of a stake or shares representing more than 50% of the Associates' share capital, the National Concessionaire is granted a right of first refusal. Although it may vary, the applicable timeframe for execution is usually six months.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

Foreign companies who wish to acquire interests outside the scope of the prospecting licence may only do so in association with the National Concessionaire and will need to provide a bank guarantee to ensure compliance with the work obligations undertaken before Sonangol.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Treaties and multinational agreements are directly enforceable only to the extent that they have been passed into law by the National Assembly of Angola, pursuant to the Angolan Constitution.

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13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Under the Petroleum Act, any dispute arising in connection with any licence or concession instruments, or between the Ministry and the licensee, or Sonangol and associates of Sonangol, will be settled by arbitration, usually in accordance with the arbitration rules established in the individual contracts, unless the matter is expressly excluded from arbitration under the Petroleum Act. The Petroleum Act does not apply to the refining, transportation, storage, distribution and commercialisation of petroleum. There is no specific regulation concerning appeals to gas sector regulator decisions. Decisions of the Ministry of Petroleum may be challenged, pursuant to the general administrative procedure established by Decree Law 16-A/95. The agency for the oil sector ("*Agência para o Sector Petrolífero*") – to be created as part of the effort to clarify Sonangol's competences – will, among other things, be responsible for settling disputes through an administrative way. This does not contradict what is stated above, but rather constitutes, most likely, a first approach towards solving any eventual dispute.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Angola is neither a signatory to the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, nor a party to the Convention on the Settlement of Investment Disputes between States and Nationals of Other States (ICSID).

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

According to Law Decree 44129 of 28 December 1961 ("Angolan Procedural Code"), any award handed down by a foreign court/foreign arbitration court is subject to judicial review upon an Angolan court to be enforceable within the national territory. In practice, any decision made by an arbitrator and/or a foreign judge must be further revised by an Angolan court in order to be valid and enforceable.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

There are some ongoing suits in relation to tax issues (profit oil, mostly) but there is no publicly available information in relation to their outcome.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Given the (not so) recent drop in oil prices, most foreign companies made an effort to withdraw or, at least, decrease their activity and costs in Angola. The need to assure a deeper political co-ordination and to avoid conflicts, and the promotion of both foreign and internal investment led to an effort by the Angolan Government towards restructuring Sonangol. Sonangol is currently involved in the research, development, production, transformation, transportation and commercialisation of oil, either directly or through its control of other companies within the sector. Although these changes have been planned since Presidential Decree 109/16 of 26 May, they still have not been made. In regards to Angola LNG, the Soyo factory resumed its activity in May 2016 (after being shut down since April 2014) and has since increased its activity. Instruction ("*Despacho*") 72/17 of 22 February has created a working group with the mission of reviewing and updating the legal framework for the sector.

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Irina Neves Ferreira is a lawyer, admitted to the Angolan and Portuguese Bars, with considerable international experience, especially in the Angolan jurisdiction. Her practice focuses on the petroleum sector, in its multiple aspects (regulatory, insurance and contractual), including matters relating to licences and concessions, transfer of participating interests and foreign exchange. Irina has a more general legal practice with involvement in operations concerning private investment, insurance law, oil & gas and real estate. She is also highly experienced in corporate compliance attained throughout her experience as counsel for the EMEA region in the international compliance team of a multinational company in the IT area. In the area of corporate and commercial law she has acted as legal advisor in several mergers, acquisitions and disposals of companies, including the acquisition and disposal of companies with head offices in Portugal and Angola, on behalf of domestic and foreign clients in various sectors, such as the oil sector, construction, information technologies and communications. Irina also provides general legal advice to numerous national and foreign companies.

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Sofia Cerqueira Serra practises in the area of corporate law and assists both national and international clients in M&A operations, negotiation of international commercial contracts and also provides regular assistance regarding their ongoing commercial activities, particularly in the areas of software licensing and intellectual property. She is also a member of the MLGTS Africa Team, an internal structure that guarantees, on a permanent basis and in close cooperation with the MLGTS Legal Circle member firms, personalised day-to-day assistance to clients on matters involving the Portuguese-speaking African countries. Within this team, Sofia regularly assists clients in the areas of oil & gas. Sofia is the author and co-author of several articles on oil & gas relating to Angola and Mozambique and frequently speaks at conferences and seminars regarding investments in these jurisdictions.

ALC Advogados is the exclusive member of the network MLGTS Legal Circle for Angola, an international network based upon the sharing of values and common principles of action with the purpose of delivering high-quality legal services to clients around the globe, to guarantee support to investors in these jurisdictions and to help them navigate through diverse business and legal environments. It was created by Morais Leitão, Galvão Teles, Soares da Silva & Associados ("MLGTS") and encompasses a select set of jurisdictions, including Portugal, Angola, Macau (China) and Mozambique. While working in close connection, the member firms combine extensive local knowledge with international experience and support of the whole network. ALC Advogados was founded by a group of lawyers of Angolan nationality with the ambition of becoming a leading law firm in Angola by offering clients a new perspective of the Angolan market and a broad range of expertise. The firm routinely assists foreign investors from various sectors and is also involved in M&A projects and tax impact analysis. It regularly assists clients working in the oil & gas sector and its client portfolio includes IOCs and oil service providers operating in Angola. The firm has attained experience while advising clients on contractual, regulatory tax and insurance matters and, overall, the full range of issues present in the lifecycle, starting with the concession and ending with decommissioning.

MLGTS is an independent full-service law firm and one of the recognised leading firms in Portugal, with more than 180 lawyers and offices in Lisbon, Porto and Funchal (Madeira). The firm has a significant international practice in all major areas of law and represents multinational corporations, international financial institutions and sovereign governments and their agencies, as well as domestic corporations and financial institutions.

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Argentina

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In 2016, Argentina's natural gas reserves were reported to be in the region of 0.4 trillion cubic metres (12.4 trillion cubic feet). According to the *BP Statistical Review of World Energy*, in the same year Argentina produced 38.3 billion cubic metres (bcm) of natural gas and consumed 49.6 bcm.

Natural gas production accounts for about 38% of the total energy production portfolio.

The largest natural gas producers in the country are Yacimientos Petroliferos Fiscales (YPF) and Total, accounting together for more than half of the production. Other significant players in the natural gas sector include Pan American Energy (a company jointly owned by BP and Bridas Corporation, which in turn is jointly owned by Argentina's Bulgheroni group and CNOOC), Petrobras, Pluspetrol, Tecpetrol, and Apache Energy.

Despite being the largest dry gas producer in South America and having the world's second-largest shale gas reserves, Argentina is a net importer of natural gas. In 2014, Argentina imported 11.8 bcm of natural gas – 5.4 bcm by pipeline and 6.4 bcm of LNG. Virtually all pipeline gas imports are sourced from Bolivia, and more pipelines from this country are under way.

Most LNG imports originate in Trinidad & Tobago and, to a lesser extent, Nigeria. Argentina has two LNG re-gasification terminals, namely GNL Escobar, which is located on the Paraná River 48 km outside of Buenos Aires, and the Bahia Blanca GasPort, which is 640 km south of Buenos Aires. Argentina does not have LNG liquefaction terminals.

Even as a net importer, Argentina continues exporting a small amount of natural gas to its neighbours.

Argentina had to resort to the importation of Chilean gas due to insufficient shipments from Bolivia.

The largest shale gas play in Argentina, Vaca Muerta, is located in the southwestern province of Neuquen. It has an estimated 308 trillion cubic feet of dry, wet, and associated shale gas resources.

Argentina's natural gas grid is comprised of 28,900 km of pipelines. There are five main gas pipelines: Gasoducto Norte; Gasoducto Centro Oeste; Neuba I; Neuba II; and San Martin.

The gas transportation pipelines systems available in Argentina are operated by the two concessionaires Transportadora Gas del Norte (that operates the main pipelines Norte and Centro Oeste) and Transportadora Gas del Sur (that operates the Neuba I, Neuba II and San Martin pipelines).

In April 2012, Argentina nationalised the largest oil company in Argentina, YPF, by expropriating Repsol's 57% controlling interest. In February 2014, Argentina agreed to pay US$5 billion to the Spanish company as settlement.

Energy subsidies were quite negligible until 2003 but since then have had a considerable impact in the federal budget. The energy subsidies originally stemmed from the set of measures adopted after the 2001 economic crisis. The Economic Emergency Law No. 25,561 converted to Pesos in 2002 the prices charged by the public utilities and forbid price adjustments and indexation mechanisms. The energy subsidies were extended many times, distorting the market and hurting the federal budget.

After taking office in December 2015, the new federal government began the difficult task of dismantling the myriad of subsidies and decided on a very high adjustment of tariffs, later overturned by the federal Supreme Court based on the failure to meet certain procedural formalities. Following such decision, the federal government conducted the necessary public hearings as requested by the Supreme Court and will put in place gradual rate increases for household and business electricity and gas, to foster new investments in the industry.

The Argentine government expects to resume exporting gas to Chile as of summer 2018, and to produce in the following four years 140 million cubic metres of gas instead of 105 million. As a result of such production increase and the implementation of a rational use plan, the government is developing foreign markets to sell the surplus.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Natural gas constitutes nearly 50% of Argentina's primary energy supply. According to the *BP Statistical Review of World Energy*, in 2016 Argentina's primary energy consumption by type of fuel was as follows:

	Oil	Natural gas	Coal	Nuclear	Hydro-electricity	Renewables	Total
Mill. tonnes oil equiv.	31.9	44.6	1.1	1.9	8.7	0.7	**88.9**

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	Oil	Natural gas	Coal	Nuclear	Hydro-electricity	Renewables	Total
%	35.88	50.16	1.23	2.13	9.78	0.78	**100**

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

In 2014, Argentina met nearly 75% of its natural gas requirements through domestic production.

In order to meet demand, Argentina imported 5.4 bcm by pipeline and 6.4 bcm of LNG. Imports by pipeline usually come from Bolivia and currently also from Chile, whereas LNG imports were sourced from Brazil (0.1 bcm), Trinidad & Tobago (3.4 bcm), Norway (0.2 bcm), other European countries (1.1 bcm), Qatar (0.9 bcm), and Nigeria (0.9 bcm).

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Argentina exports natural gas to Chile and, to a lesser extent, Uruguay. According to the U.S. Energy Information Administration, exports in 2013 amounted to 0.1 bcm.

Under Decree Nº 893/2016, the Ministry of Energy and Mining shall issue an export authorisation in cases of temporary exports for assistance in emergency situations and those that are necessary to enable the use of the infrastructure of neighbouring countries to facilitate the transport of natural gas to the Argentine domestic market, allowing increased production of local origin.

In October 2017, Argentina and Chile entered into the first power swap agreement, allowing both countries to input gas or electricity in a geographical point and to obtain supplies in another one over their long border.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Oil proved reserves in Argentina amounted in 2016 to 2.4 billion barrels (300 million tonnes), with a reserve-to-production ratio of 10:6, according to the *BP Statistical Review of World Energy*.

Argentina is one of the very few countries that has achieved production of commercial volumes of tight oil. In 2014, tight oil production increased, and it did so at a faster rate than non-tight oil production. Tight oil production originates in the Vaca Muerta shale oil and gas field, where YPF, jointly with Chevron, produces around 20,000 barrels per day (bpd).

The state-owned oil company YPF has been announcing large investments jointly with the likes of Chevron, Total, Pan American Energy and Wintershall in excess of US$1,100 million in non-conventional gas. The projects will take shape in the next four years, after which it is expected that the conventional production and the one from Vaca Muerta will become similar. This will revert the situation of the last decade of divestments in the energy sector that caused Argentina to lose self-sufficiency.

The country has 10 refineries with a combined 622,000 bpd refining capacity, which is not sufficient to meet domestic demand. In 2014, according to the U.S. Energy Information Administration, Argentina imported 43,494 bpd from the U.S. YPF controls half of Argentina's refining capacity. Shell has the second largest refining capacity in the country.

The oil transportation network system includes the following pipelines: Puesto Hernández – Luján de Cuyo; Puesto Hernández – Talcahuano (Chile); Puesto Hernández – Medanito; Medanito – Allen; Plaza Huincul – Challacó; Challacó – Allen; Plaza Huincul – Allen; Puerto Rosales – La Plata; Palmar Largo – Juarez; Las Heras – Pico Truncado; Pico Truncado – Caleta Olivia; El Treból – Caleta Córdova; and Jepenner (Brandwen) – Campana. Most of them are operated by YPF or by companies affiliated with YPF.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

As indicated in question 1.2 above, in 2016, 35.88% of Argentina's energy requirements were met using oil.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

In 2016, Argentina produced 29.8 million tonnes (629,000 bpd) and consumed 30.9 million tonnes (662,000 bpd), according to the *BP Statistical Review of World Energy* (June 2017).

2.4 To what extent is your jurisdiction's oil production exported?

In 2014, Argentina exported 237,000 bpd (1.02 million tonnes), according to the Joint Organisations Data Initiative.

According to the U.S. Energy Information Administration, 29,000 bpd of crude oil and 8,000 bpd of oil products were exported to the U.S. in the same year.

Law No. 25,561 of Public Emergency and Amendment of the Currency System of 2002 and Decree Nº 310/2002, on withholdings to oil and fuel exports, both ceased to apply on January 6, 2017.

The Argentine government also ratified the decision to release the internal price in the liquid fuel market and announced by means of Decree Nº 962/2017 of November 24, 2017 that the guidelines for the import of crude oil and by-products set by Decree Nº 192/2017 will cease to apply on December 31, 2017.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Argentina is a federal republic with 23 provinces and a federal district, the Autonomous City of Buenos Aires, and also the federal capital.

Each province enacts its own constitution and regulatory framework and all powers not delegated to the Federal Government in the National Constitution are kept by the provinces.

Oil and gas activity in Argentina has been heavily controlled and regulated by the government since the early discoveries in the

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nineteenth century. Most activities were historically performed by the state-owned companies YPF and *Gas del Estado*. The private sector had a limited role in the business, with a higher market participation in downstream.

From the 1920s up to 1989, the Argentine government dominated both the upstream and downstream segments of the oil and gas industry.

The so-called Hydrocarbons Act Nº 17,319, enacted in 1967, sets forth the basic legal framework for crude oil and natural gas exploration and production, following the above-described trend of intense state activity and control, and granting to the federal state the property and mining rights over all existing hydrocarbon reserves in the territory of Argentina.

Although the Hydrocarbons Act Nº 17,319 allows the National Executive Branch to grant exploration permits and production concessions to private parties, prior to 1989 such concessions were seldom granted and almost all oil exploration and production in Argentina was carried out by or on behalf of the state-owned oil company YPF. Notably, however, a substantial volume of oil was produced by private companies operating under service contracts with YPF. Under this system, crude oil, whether extracted by YPF or by private companies operating under service contracts, was delivered to YPF, and the Secretariat of Energy distributed the same among the refining companies according to quotas. At the same time, the National Executive Branch set official prices for crude oil and refined petroleum products at levels which in many cases were lower than the international prices.

In August 1989, the federal congress enacted the so-called State Reform Act Nº 23,696 and the Economic Emergency Act Nº 23,697 that provided the legislative basis for the deregulation of the economy and the privatisation of Argentina's state-owned companies, granting the President broad authority to reorganise such companies, and also declaring certain state assets and most state-owned companies to be subject to privatisation.

Following the State Reform Act and the Economic Emergency Act, a series of presidential decrees relating specifically to deregulation of energy activities were issued, among them Decrees Nº 1055/89, Nº 1212/89 and Nº 1515/89, which laid the foundations for energy deregulation, eliminated restrictions on imports and exports of crude oil, and deregulated the domestic oil industry including the prices of oil products.

Based on the deregulatory decrees, in the 1990s, service contracts were turned into concessions, with a free disposal regime, and freely negotiated prices.

In 1992, natural gas transportation, storage, distribution and commercialisation were regulated by the Natural Gas Act Nº 24,076, setting an open-access regime.

After the economic crisis of 2001, legislation and regulations – including the Economic Emergency Act Nº 25,561 – were enacted, limiting the 1990's regime and imposing further government controls on prices and disposal of production.

Under the Law Nº 24,145 enacted in 1992 and the Law Nº 26,197 enacted in 2007, that partially amended the Hydrocarbons Act Nº 17,319, the provinces assumed the ownership and administration of the hydrocarbon deposits within their boundaries, and thus the power to grant concessions on them. The federal government kept the power to enact general energy legislation. Regarding offshore deposits, they belong to the provinces for up to 12 nautical miles offshore, and beyond 12 nautical miles they belong to the federal government.

Moreover, the 1994 amendment to the Federal Constitution confirmed that gas and oil fields are owned by the Federal Government or the Provinces depending on the jurisdiction where fields are located, as mentioned.

Additional steps were taken towards deregulation of the energy sector, including: (i) the offering under international calls for bidding of exploitation concessions for certain marginal areas previously operated by YPF; (ii) the offering of association agreements with YPF for the exploration and exploitation of certain major producing areas held by YPF; (iii) the transformation of existing exploration service contracts with YPF into exploration permits; (iv) the transformation of existing production service contracts with YPF into exploitation concessions; (v) the elimination of official prices for crude oil and refined products; and (vi) the deregulation of gas wellhead (*Boca de Pozo*) prices as of January 1, 1994.

In September 1992, the mentioned Law Nº 24,145 provided for the privatisation of YPF, pursuant to which the federal and provincial governments sold the privatised YPF's shares in public offerings.

In 1992, the federal congress passed the Natural Gas Act Nº 24,076, which set forth the basis for deregulating the transportation and distribution of natural gas, the sale of the assets of the state-owned company *Gas del Estado* to private companies, the granting of licences to operate such assets, the establishment of a regulatory framework for the industry and the creation of a regulatory body to oversee the industry.

Under the Natural Gas Act Nº 24,076, the transportation and distribution systems of *Gas del Estado* were organised into two transportation companies and eight distribution companies transferred to private investors. The gas industry was further regulated by Decrees N° 1189/92, 1738/92, 2255/92, 1186/93, 1186/94 and 1411/94.

In 2012, the so-called Hydrocarbons Sovereignty Act Nº 26,741 and the regulatory Decree Nº 1277/12 limited the free disposal regime, including larger state intervention in oil and gas exploration, production, refining and marketing. Also, importantly, the Hydrocarbons Sovereignty Act Nº 26,741 expropriated Repsol YPF S.A., the formerly state-owned YPF that had been privatised in 1992.

Later, Decree Nº 929/2013 set incentives for oil and gas declining exploration and production.

A new Hydrocarbons Act Nº 27,007 enacted in 2014 aimed at creating incentives to encourage long-term foreign oil and gas investment, as declining production and increasing imports made it necessary to boost exploration and production, particularly the non-conventional one, especially in potentially rich shale oil and gas areas such as world-class Vaca Muerta. The Hydrocarbons Act Nº 27,007 also provides for reduced royalties when the business model so warrants because of the quality of the oil produced, the geology of the field or the location of the deposit.

The federal regulatory authority is the *Secretaría de Energía* (Sectretariat of Energy), within the *Ministerio de Energía y Minería* (Ministry of Energy and Mining).

The regulatory authority for the transportation and distribution of natural gas is the *Ente Nacional Regulador de Gas* (Federal Gas Regulatory Authority) created in 1992 at the federal level and regulated by Decree Nº 2255/92. At the local level, each province may have its own regulatory agency and regulate the local activities accordingly. The Ministry of Energy and Mining has conducted a review of the tariffs in order to design a tariff adjustment that will foster the investments necessary to expand the network to reach more households, improve service quality and maintain high safety standards. The aim of the Ministry of Energy and Mining by readjusting tariffs is to turn resources into reserves and then into production, and replace importations.

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The Ministry of Energy and Mining created, by means of Resolution Nº 46-E/2017, a programme to encourage investments in natural gas production from non-conventional reservoirs in the Neuquén basin, which will remain valid until December 31, 2021. The companies joining the programme could receive compensations and must provide insurance bonds through policies approved by the National Superintendence of Insurance.

Decree Nº 629/2017, issued to comply with the policies of the National Government to improve productivity and competitiveness of local producers, created a Regime of Importation of Used Goods in the Hydrocarbon Industry to expedite the importation of used equipment that the local industry does not supply, as well as to incorporate new technologies and management modalities that contribute to the development and promotion of the sector.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Over time, oil and gas activities in Argentina have been undertaken under a myriad of legal forms, ranging from full concessions, to service contracts, including joint ventures and different kinds of agreements.

The federal government and the provinces may enter into contracts for the exploration, development and exploitation activities in their respective jurisdictions, with foreign or local, private or public companies. There is a wide range of possibilities for the provinces to do so, including granting exploration permits and exploitation concessions.

The Hydrocarbons Act Nº 27,007 enacted in 2014 to encourage long-term oil and gas investment, included a model bidding process to harmonise the bidding conditions, drafted with the participation of the provinces and the federal government.

Under the mentioned bidding process, concessions are awarded to the most suitable bidder, taking into consideration levels of investment and the exploration activities offered by the bidder.

Once an exploration permit holder finds commercially exploitable oil or gas, the investor may request an exploitation concession to benefit from the exclusive right to produce hydrocarbons from the concession area.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The terms of an exploration permit depends on the bidding conditions applicable to each contract and are divided into sub-periods.

Exploration permits for conventional exploration comprise two sub-periods of up to five years each, plus a potential extension of a further five years.

In turn, exploration permits for non-conventional exploration comprise two sub-periods of up to four years each, plus a potential extension of five years.

In all cases, offshore exploration permits include an additional one-year term.

Any unused time in the exploration period may be added to the production concession term.

As to exploitation concessions, the general term for onshore conventional exploitation is 25 years, for offshore conventional exploitation it is 30 years, and for non-conventional exploitation it is 35 years. In the case of non-conventional exploitation, the 35-year term includes five years to develop a pilot plan.

The provinces may grant extensions of up to 10 years to producers that comply with the investment as undertaken.

Natural gas transportation concessions are granted for 35-year terms, which may be extended for up to 10 additional years.

Provincial government royalties are harmonised at 12%, payable by the exploitation concessionaires to the provinces that granted the concession. The royalty rate may be increased by 3% for each concession extension, subject to a maximum rate of 18%.

The mentioned extensions, which must be applied for at least one year in advance, may be awarded every 10 years to the concessionaires that have met their investment requirements.

Since the enactment of the Hydrocarbons Act Nº 27,007, state-owned companies, federal or provincial, may not be awarded reserved areas (not open to other bidders).

All concessions are subject to early termination in case of breach of the terms of the concession.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

The hydrocarbons industry in Argentina has for the most part been heavily controlled and regulated by the state, with periods in which oil and gas activities were deregulated and state-owned companies privatised. The main state-owned companies in the industry, YPF and *Gas del Estado*, were included in a privatisation programme initiated in 1992.

Previously, in 1989, the mentioned Decrees Nº 1055/89, Nº 1212/89 and Nº 1515/89 had initiated the path to the oil and gas industry's deregulation, and service and take-or-pay contracts were turned into free disposal concessions.

In 1992, natural gas transportation, storage, distribution and commercialisation were opened up to private investment by the Natural Gas Act Nº 24,076.

After 2001 the state became again increasingly active in regulating and participating in the oil and gas industry, with heavier intervention legislation and regulations at the federal and provincial level.

Among the most important pieces of legislation in the field, in 2012 the Hydrocarbons Sovereignty Act Nº 26,741 set the tone for heavier state intervention in oil and gas exploration, production, refining and marketing and called for the expropriation of 51% of the shares owned by the Spanish company Repsol in Repsol YPF S.A., the private company that was the continuation of the formerly state-owned YPF, privatised in 1992. Immediately thereafter, the government took possession of the expropriated shares and YPF's assets. The expropriation just applied to Repsol YPF S.A., and to no other company or oil and gas assets.

Declining hydrocarbons production and increasing imports to cope with domestic demand led to legislation designed to boost exploration and production, particularly in the non-conventional fields. The Hydrocarbons Act Nº 27,007 enacted in 2014 is a milestone in this new turn in governmental policy towards private participation in the oil and gas industry in Argentina.

Based on the Hydrocarbons Act Nº 27,007, the government-issued regulations aimed at encouraging production to correct the oil price decline, as well as improve the conditions for badly needed exploration. Special attention is given in the regulations of Argentina's shale gas reserves, considered to be among the largest in the world.

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In 2017, YPF reached its highest level of non-conventional gas production through its operations at the Vaca Muerta oil field located in Neuquén, with a total volume of 11.36 million daily cubic metres.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Provincial government royalties are currently harmonised at 12%, calculated at wellhead, payable on a monthly basis by the exploitation concessionaires to the provinces that granted the concession. The royalty rate may be increased by 3% for each concession extension, up to a maximum of 18%.

The Hydrocarbons Act Nº 27,007 provides for the potential reduction of the applicable royalties when the business conditions make it advisable because of the quality of the oil produced, the geology and productivity of the field or the geographic location of the deposit.

The exploitation concessionaires and the holders of exploration permits also pay a canon that varies depending on the exploration or production area awarded.

In addition to the canon and royalties, the federal, provincial and municipal governments levy the taxes applicable at each level in accordance with the federal constitution, the provincial constitution and the applicable laws, e.g. federal income tax, value-added tax, stamp tax, gross income tax, and the like.

3.6 Are there any restrictions on the export of production?

In relation to the export of production, there is no legislation specifically prohibiting it, but in practice, exports have not been permitted due to the impossibility of obtaining the necessary administrative clearings.

Under Decree Nº 893/2016, the Ministry of Energy and Mining shall issue an export authorisation in cases of temporary exports for assistance in emergency situations and those that are necessary to enable the use of the infrastructure of neighbouring countries to facilitate the transport of natural gas to the Argentine domestic market, allowing increased production of local origin.

Law Nº 25,561 of Public Emergency and Amendment of the Currency System of 2002 and Decree Nº 310/2002, on withholdings to oil and fuel exports, both ceased to apply on January 6, 2017.

The Argentine government also ratified the decision to release the internal price in the liquid fuel market and announced by means of Decree Nº 962/2017 of November 24, 2017 that the guidelines for the import of crude oil and by-products set by Decree Nº 192/2017 will cease to apply on December 31, 2017.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

After taking office in December 2015, the new federal government repealed the complex foreign exchange controls regime formerly in force. International markets consider opening to foreign currency and the reaching of a settlement with the foreign bondholders, ending a default lasting for over a decade, as the correct moves to attract new foreign investments.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Government policy is that hydrocarbons companies must prioritise domestic demand requirements.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Under the Hydrocarbons Act Nº 27,007 on the oil and gas model bidding process, the bidding conditions set, among other conditions, the kinds and amounts of guarantees to be provided by the hydrocarbons companies bidding for concessions.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The rights to develop and produce oil and gas from reserves under concessions may be used as collateral and booked for accounting purposes in compliance with local, generally accepted accounting principles.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

The following authorisations, among others, are required for an oil and gas company to obtain exploration permits and production concessions to develop and produce oil and gas:

a) Corporate registrations including that of the legal entity before the applicable General Inspection of Corporations.

b) Tax registrations including that before the applicable federal, provincial and municipal tax authorities.

c) Labour and health and safety registrations, including those before the applicable federal, provincial and municipal labour, social security and health and safety authorities. The government generated new conditions for the applicable collective labour agreements with different unions in order to permit clauses which are more flexible and to achieve higher competitiveness in the activity.

d) Environment-related registrations and compliance and monitoring before the applicable federal, provincial and municipal authorities, including mandatory environmental impact assessments, approvals and renewals.

e) The current government is implementing decisions to reduce the number and complexity of procedures and approvals.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Resolution Nº 5/96 of the Secretariat of Energy regulates the process applicable to the abandonment or decommissioning of oil and natural gas projects.

The regulations govern two kinds of abandonment of hydrocarbons wells, the temporary one and the definitive one.

The concessionaire must submit to the enforcement authority an abandonment or decommissioning plan in advance for approval. The enforcement authority may in turn request amendments to the abandonment or decommissioning plans based on technical grounds.

The term available to the concessionaire to complete the abandonment or decommissioning plan depends on the kind of field

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being abandoned and other technical, economic and operational aspects involved.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/ requirements of the legislation?

Under the Secretariat of Energy Resolution Nº 709/2004, all entities that operate storage tanks, or any kind of liquefied petroleum gas storage with a capacity exceeding 1,000 kilograms, must be registered before the *Registro Nacional de la Industria de Gas Licuado de Petróleo* (Liquefied Petroleum Gas Industry National Registry). Such entities must comply with all requirements and regulations, among them the periodical security audits certifying the operating conditions of their installations, and obtaining the registration certificate.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Intending to curtail the effects of the diminishing natural gas available to the domestic market, the Ministry of Economy issued Resolution Nº 534/2006, which regulates the import and export of natural gas. The government also caused the *Dirección General de Aduanas* (General Customs Authority) to apply as a basis for the valuation of natural gas exports, the highest price set for the importation contracts of natural gas into Argentina.

The export of natural gas requires the prior approval of the Secretariat of Energy. Resolution Nº 299/98 of the Secretariat of Energy regulates natural gas exports, setting forth the limitations applicable and the requirements necessary to obtain the prior approval of the Secretariat of Energy. Further regulations are contained in Decrees Nº 885/92, 1738/92, 2255/92, 1186/93 and 2731/93.

As a general rule, the Hydrocarbons Act Nº 17,319 and the Natural Gas Act Nº 24,076 provide that approvals for the export of natural gas will be granted insofar as they do not affect domestic supply.

Under the Natural Gas Act Nº 24,076, natural gas imports do not require prior approval.

In any event, copies of the import and export agreements must be filed before the Federal Gas Regulatory Authority.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

In relation to restrictions on the export of production, there is no legislation specifically prohibiting it, but in practice exports have not been permitted due to the impossibility of obtaining the necessary administrative clearings, and the trend is to permit them definitively.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

The transportation of natural gas is regulated by the Natural Gas Act Nº 24,076, which defines natural gas transportation as a public service.

Concessions for the transportation and distribution of natural gas are granted by the federal state and the provinces. Concession holders have the obligation to build, maintain and operate pipelines in accordance with the terms of the concession and the applicable legislation.

The federal and provincial governments may only provide transportation services if there are no private entities willing to be awarded a transportation concession in a specific area.

Under the Hydrocarbons Act Nº 17,319, a production concession grants the concessionaires the right to obtain a transportation concession to transport their hydrocarbons production. Such concession allows the construction and operation of pipelines, and is subject to the obligation to provide open access to third parties to their transport infrastructure, pursuant to applicable regulations, provided they have capacity available.

As to the transportation of liquid hydrocarbons, the Secretariat of Energy Resolution Nº 1460/06 sets forth the technical and safety requirements and standards applicable to oil pipelines, the concessionaires of which have been granted transportation concessions beyond the limits of their production concessions.

Regulations and requirements applicable to fuel storage facilities may be found under Law Nº 13,660 and Decree Nº 10,877/60.

Moreover, Law Nº 26,095 levies special fees on the users of the transportation facilities to be used to expand the natural gas transportation pipeline network so as to promote domestic industry supply, other than for works that the concessionaires must undertake themselves under their contracts.

Resolution Nº 120-E/2017 approved the technical regulation for the transportation of liquid hydrocarbons applicable to oil pipelines, polyducts and facilities subject to a transportation concession under Law Nº 17,319, extending it to all oil pipelines that transport crude oil. Along these lines, Resolution Nº 18-E/2017 calls for bids for the acquisition of pipelines for the project "Expansion of the system of transportation and distribution of natural gas". Under the mentioned Resolution, the first bidding process includes the construction of the Regional Centro II pipeline in the province of Santa Fe, the upgrade of the coastal and Tandil-Mar del Plata pipelines in the province of Buenos Aires, as well as the Cordillerano Patagónico pipeline in Chubut and Río Negro.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The following authorisations, among others, are required from a company intending to construct and operate oil and natural gas transportation pipelines and associated infrastructure, in addition to being awarded the necessary concession by the federal or provincial authority:

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(a) Corporate registrations, including that of the legal entity before the applicable General Inspection of Corporations.

(b) Tax registrations including that before the applicable federal, provincial and municipal tax authorities.

(c) Labour and health and safety registrations including those before the applicable federal, provincial and municipal labour, social security and health and safety authorities. The government generated new conditions for the applicable collective labour agreements with different unions in order to permit clauses which are more flexible and to achieve higher competitiveness in the activity.

(d) Environmental and related registrations and compliance monitoring before the applicable federal, provincial and municipal authorities, including the mandatory environmental impact assessments, approvals and renewals.

Resolution Nº 1460/2006 sets forth the regulatory framework applicable to the pipeline transportation of oil and approved the Technical Rules for the Transportation of Liquid Hydrocarbons in Pipelines.

(e) The current government is implementing decisions to reduce the number and complexity of procedures and approvals.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Pipelines that run through two or more provinces are subject to federal legislation and jurisdiction.

Pipelines located exclusively in a province are subject to the jurisdiction of such province, although they must comply with all applicable federal regulations.

Pipeline concessionaires have to secure the necessary land to construct and operate their pipelines, which they may do by means of acquiring the land or requesting easements to the competent enforcement authority.

Under the Hydrocarbons Act Nº 17,319, since hydrocarbons activities are considered of national interest, the surface land owners may not oppose the use of their land if it is necessary, but they must be compensated by the concessionaires for damages caused to the properties affected by the activities. The interested parties may either claim determination of the respective damages amount by the appropriate authority, or determine them by mutual agreement.

In order to determine the compensation, land owners may resort to the courts and produce evidence of the alleged damage. Since it is not always easy to determine or quantify the damages, the Hydrocarbons Act Nº 17,319 provides a second alternative mechanism of compensation to the land owner based on the characteristics of the different areas where the activities are carried out.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Pipelines and other hydrocarbon transportation infrastructure are governed under the general open-access principles, whereby third parties have access to the infrastructure subject to the applicable regulations. Thus, pipelines subject to the Hydrocarbons Act must permit the transportation of hydrocarbons belonging to third parties, provided they have available capacity.

Carriers are not allowed to give advantages or preferences to any third party, unless such preferences or advantages are based on objective criteria accepted by the enforcement authority.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Gas transportation systems are governed by the Natural Gas Act Nº 24,076, the Hydrocarbons Act Nº 17,319, the Hydrocarbons Act Nº 27,007, and the regulations issued by the Federal Gas Regulatory Authority and the Secretariat of Energy at the federal level.

The Federal Gas Regulatory Authority has broad governing and control powers that include: (a) issuing regulations on gas sales, transportation and distribution activities; (b) preventing monopolistic or discriminatory behaviour; (c) approving the tariff frameworks applicable to gas utilities and adjustments thereto; (d) monitoring all matters related to the technical operation of the gas transportation systems; (e) approving transfers of controlling interests in gas transportation and distribution companies; (f) approving the construction, expansion or abandonment of major facilities; (g) inspection and testing of facilities; and (h) imposing warnings and fines in accordance with the Natural Gas Act Nº 24,076, the applicable regulations and the terms of the particular transportation concession.

Decisions by the Federal Gas Regulatory Authority under the Natural Gas Act Nº 24,076 are subject to judicial review. Disputes among regulated entities or between regulated entities and third parties arising from the distribution, storage, transportation or marketing of natural gas must be submitted to the Federal Gas Regulatory Authority, whose decision may be appealed by means of administrative proceedings before the federal administration and thereafter before the applicable federal courts.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Gas distribution companies must operate in accordance with the terms of the concession granted to operate their networks.

A licence grants the right to distribute natural gas within a specified geographic area. The concession to distribute gas does not include the exclusive right to sell gas within the same area; under certain circumstances, consumers may purchase gas directly from producers or brokers.

The Argentine legal system adheres to the open-access principles whereby licence holders must assure to all users open and non-discriminatory access to the gas transportation and distribution network operated by them.

Under their licences, the distribution companies must on a regular basis receive, transport and sell gas through their distribution systems, keep all equipment and facilities in good operating condition, establish adequate measurement and control systems, improve and preserve the ecosystems in which they operate, and interrupt the service rendered to large users when necessary in order to maintain an adequate level of supply for residential and other commercial users, as directed by the enforcement authority. The licences granted imply the obligation to keep certain infrastructure investments.

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The Natural Gas Act Nº 24,076, and Decree Nº 2255/92 regulate the tariffs that the distribution companies may charge, and mandate that the gas price must be based on the cost of the gas purchased at the point of entry into the transportation system, a transportation charge, and a distribution commensurate with a reasonable return on investments.

The Federal Gas Regulatory Authority has to periodically review and adjust the tariffs in accordance with the policies set forth under the Natural Gas Act Nº 24,076 and the licences and with the aim of fostering efficiency.

Since taking office, the current federal government began dismantling the complex subsidies regime formerly in place and is implementing an adjustment of tariffs, conducting the public hearings and other necessary formalities, to foster new investments.

It is not mandatory for the transportation companies to expand their existing gas transportation pipelines network at the request of a third party. If a transportation company is not willing to expand its transportation capacity upon the request of the customers, however, the federal and local authorities may grant new concessions, so that other plays may enter the market and build the necessary pipelines to satisfy the increasing demand.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Transportation tariffs are indicated in the terms of the bidding conditions of each concession. Transporters must charge the same tariffs to all customers, unless due to the location, type of services or any other reason, the enforcement authority authorises a different tariff.

The price of the gas is subject to different regulations and agreements entered into between the federal government and the natural gas producers.

The Commission for Planning and Strategic Coordination of the National Hydrocarbons Plan, created by Decree Nº 1277/2012, may establish the criteria applicable to the commercialisation of hydrocarbons to ensure reasonable prices, and may set referential sale prices of hydrocarbons and fuels. In practice, rates are strictly regulated by the government in relation to the macroeconomic needs, although the current federal government is implementing the administrative and regulatory improvements necessary to foster new investments.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

See above.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

A private entity interested in distributing gas must be awarded a distribution concession. Concessions are granted for 35 years and may be extended for 10 years.

Provincial authorisations are also required to construct, operate and maintain gas distribution networks.

Concessions are subject to early termination in case of breach of the terms of the concession.

7.3 How is access to the natural gas distribution network organised?

Gas distribution companies must allow free access to their systems to every third party. Third parties enjoy open access to the transport infrastructure under the applicable regulations.

Distributors may not grant any advantage or preference to any third party, unless such preferences or advantages are authorised based on objective criteria as determined by the Federal Gas Regulatory Authority.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

The terms and conditions of a concession may require distributors to undertake the investments and works necessary to expand their systems to accommodate new customers.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Tariffs for accessing the distribution network are regulated in the terms and conditions of the gas distribution concessions. Distributors must charge the same tariffs to all customers, unless due to the location, type of services or any other reason, the Federal Gas Regulatory Authority authorises a different tariff scheme.

The Commission for Planning and Strategic Coordination of the National Hydrocarbons Plan, created by Decree Nº 1277/2012, may establish the criteria applicable to the commercialisation of hydrocarbons, to ensure reasonable prices, and may set referential sale prices of hydrocarbons and fuels. In practice, rates are strictly regulated by the government in relation to the macroeconomic needs.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Under the Natural Gas Act Nº 24,076, gas transporters and entities controlling or controlled by gas transporters may not control gas distribution companies.

Consumers purchasing natural gas directly from producers may not control distribution companies that provide gas distribution services in the area where such consumers operate.

Likewise, no producer, gas storehouse owner, natural gas distributor, customer who purchases natural gas directly from producers, any group thereof or any company affiliated therewith, may hold a controlling interest in a transportation company.

Gas distribution is considered a public service, and thus distributors may not sell, encumber, lease, sublease or assign the assets necessary to render the distribution service, without the prior authorisation of the Federal Gas Regulatory Authority.

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8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

The legal framework for gas trading is mainly regulated in the Natural Gas Act Nº 24,076 and the regulations issued pursuant to it. Decree Nº 180/2004 updated the regulation of the *Mercado Electrónico del Gas* (electronic wholesale market for natural gas or MEG), in which gas traders and gas producers participate, who must be registered before the Secretariat of Energy.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

In 2004, the federal government introduced certain modifications to the gas market regulations applicable to operations different from a strict bundle structure, and created a fund for investments in transportation and distribution of gas. The regulation also classified consumers into different categories, depending on their gas expenditures.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Resolution Nº 338/2012 of the Secretariat of Energy approves the Terms for the Liquefied Natural Gas Operation Terminals and sets forth the applicable regulations. To enhance the security of the process, the regulations created a Registry of Independent Professionals.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The Secretariat of Energy and may delegate supervision and control activities on the Federal Gas Regulatory Authority.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The Secretary of Energy determines reference prices (below export parity prices) with the goal of guaranteeing regular supply in the domestic market and may establish price stabilisation mechanisms in order to avoid price fluctuation in the domestic market.

Also, the Secretariat of Energy, together with the Antitrust Commission, will perform an analysis of the sector, including the behavioural patterns of its agents, for the purpose of fixing limits at certain levels at each stage of vertical integration of the industry.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

The fall in gas production combined with a strong economic growth resulted in massive investments in LNG re-gasification projects. With the government unlikely to threaten economic growth by loosening price controls further, Argentina is expected to keep investing in LNG re-gasification capacity.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Law N° 13,660, enacted in 1949, and Decree Nº 10,877/60 enacted in 1960, govern the refining, elaboration, transformation and storage of solid, liquid or gaseous hydrocarbon products.

The mentioned activities are also subject to registration requirements set forth by the Secretariat of Energy. The Secretariat of Energy is also the enforcement authority of Law N° 13,660 and Decree Nº 10,877/60, and as such may approve applications to build new refineries or modify or upgrade existing ones.

Any refinery must comply with federal and provincial environmental and safety regulations, which includes a previous report about the environmental impact on the area in which the refinery or plant will be built or upgraded, and a certificate on safety report about the project by a safety auditing firm, previously registered under a special registry before the Secretariat of Energy.

Also under the Secretariat of Energy, Resolution Nº 450/94 provides that any company who applies for refining or commercial activities must be registered under the Registry of Oil Companies of the Secretariat of Energy.

More recently, Decree Nº 1277/2012 regulates the so-called Hydrocarbons Sovereignty Act Nº 26,741 and the Federal Plan for Hydrocarbons Investments. Under Decree Nº 1277/2012, upstream and downstream companies must register before the Federal Registry of Hydrocarbons Investments and submit investment programmes on an annual basis. The investment programmes are subject to the approval of the Commission for the Strategic Planning and Coordination of the Federal Plan of Hydrocarbons Investments. The Commission is vested with broad regulatory and enforcement powers including controlling costs and setting prices. The export of crude oil, natural gas and by-products is subject to prior governmental approval.

The Natural Gas Act Nº 24,076 also governs transportation, storage, marketing and distribution of natural gas and considers transportation and distribution as public services.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The terms and conditions applicable to the sale of hydrocarbons by producers to refineries are freely negotiated between the parties. In any event, local prices are affected by price controls and export limitations.

The Commission for Planning and Strategic Coordination of the National Hydrocarbons Plan, created by Decree Nº 1277/2012, has broad powers to determine the criteria for the commercialisation of hydrocarbons with the aim of ensuring reasonable prices.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

Competition aspects are generally governed by the Antitrust Act N°

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25,156 and the related regulations. Although the Antitrust Act Nº 25,156 calls for the organisation of an independent Antitrust Court, such court has not yet been created, and enforcement is still in the hands of the *Comisión Nacional de Defensa de la Competencia* (Antitrust Commission), which is not an independent court but an administrative agency that depends on the Secretariat of Commerce.

In relation to the gas market, there is an additional control as the Federal Gas Regulatory Authority also has powers to approve or reject potential concentrations in the gas market.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The Antitrust Act Nº 25,156 considers as anti-competitive any activity or conduct related to the production and exchange of goods or services that has the purpose or effect of limiting, restricting or distorting competition or market access or abuse of a dominant position in a market, to the extent of being harmful to general economic interests.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The control and investigation of anti-competitive practices are carried out by the Antitrust Commission, which has broad investigative powers, including the right to: (a) request from private parties the submission of relevant information, documentation, commercial books, and any other document or report that may be useful to the investigation; (b) convene public hearings; and (c) request from the competent courts the issuance of search warrants to access the premises of the parties being investigated. The resolutions of the Antitrust Commission may be appealed before the competent Court of Appeal.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

In relation to the natural gas sector, the Antitrust Commission and the Federal Gas Regulatory Authority have the power to approve or reject any proposed amalgamation, change of control or merger in the gas industry. Each of those entities works at different levels, it even being possible that a proposed transaction be approved by one and rejected by the other.

Under the Antitrust Act Nº 25,156 and as part of the merger control procedure, the Antitrust Commission has to request the opinion of the Federal Gas Regulatory Authority in gas-related transactions.

A previous filing before the Antitrust Commission is mandatory for concentration transactions exceeding certain amount thresholds as set forth in the Antitrust Act Nº 25,156.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There are no such specific regulations prohibiting foreign investment in the natural gas sector.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Under Argentine law, international treaties entered into and approved as mandated under the Federal Constitution have precedence over local laws and regulations. In other words, local laws and regulations must be consistent with the principles and obligations set forth in foreign treaties entered into by Argentina.

In the gas industry, for example, Argentina has signed treaties with Bolivia for the importation of natural gas.

In October 2017, Argentina and Chile entered into the first power swap agreement, allowing both countries to input gas or electricity in a geographical point and to obtain supplies in another one over their long border.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Any controversy or dispute between producers, transporters, distributors, consumers or any third interested party (be they individuals or legal entities), arising from any service rendered under the Natural Gas Act Nº 24,076, must be initially submitted to the Federal Gas Regulatory Authority.

The resolutions of the Federal Gas Regulatory Authority are subject to appeal before the Federal Administrative Appellate Court.

Administrative fines and penalties imposed by the Federal Gas Regulatory Authority may also be appealed before the Federal Administrative Appellate Court.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Argentina is a signatory party and has duly ratified as domestic

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legislation the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the Convention on the Settlement of Investment Disputes between States and Nationals of Other States (ICSID).

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

Argentina is a party to several international conventions to facilitate foreign investors' ability to enforce awards against the government. In practice, however, there have been cases in which the government has challenged the enforcement of such adverse awards. Moreover, in the renegotiation of some utility agreements such as those of gas distribution companies, the government requested, as a condition of the renegotiation, the waiver by the utility companies to their rights under the bilateral investment treaties and the ICSID.

Argentina has entered into different co-operation and commercial agreements in order to intensify investments in different areas, including the ones with Germany, Israel, Italy, Japan and Spain.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

The cases *CMS* and *Sempra* both involved litigation regarding breaches in the gas industry. CMS was an investor in the gas transmission company Transportadora de Gas del Norte, and Sempra was an investor in the distribution companies Sodigas Pampeana and Sodigas Sur. Both the *CMS* and *Sempra* awards upheld the plaintiffs' complaints that the government had breached the "fair and equitable treatment" clauses under the applicable bilateral investment treaties. Thus, CMS and Sempra were awarded several millions in damages. After the award to CMS was released in 2005, the government filed two motions against the ICSID panel awards, requesting a declaration that the award was null, and a stay against the execution of the award until the aforesaid nullification motion were decided. After hearing the government commitment to comply with the decision, the ICSID panel granted the motion to stay the execution of the award. The case ended with a settlement.

The *Sempra* case also ended when the shareholders sold their stake and the buyer entered into a settlement agreement with the government.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

The federal government continued implementing a number of measures hailed by the international markets as the correct moves to attract additional foreign investment in the oil and gas and other sectors, including opening the access to foreign currency, eliminating limitations to inbound and outbound money movements, reaching settlements with foreign bondholders, and dismantling complex formalities and procedures formerly in place. These developments have been widely supported by the current administration success in the October mid-term congressional elections all around the country. Moreover, the government is poised to successfully approve in Congress, before the congressional calendar, bold labour, tax and social security legislation that will enhance the conditions for investment in many areas, including oil and gas.

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Estudio Randle provides comprehensives legal advice to domestic and international clients and governments, primarily in business transactions, natural resources, real estate, infrastructure, corporate, litigation and tax matters.

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Stone Pigman Walther Wittmann PLLC has extensive experience assisting clients in all aspects of energy-related transactions, business formations, project financings, M&A, strategic alliances and the purchase and sale of major energy assets. In addition to developing project structures, we often serve as lead counsel on contracts for joint ventures, joint operations, sales and purchases, processing, services, transportation, development, investment, production sharing, farm-out agreements, drilling, storage, construction, operation and management and technology licensing.

We have handled hundreds of domestic and international energy deals that involve the exploration, extraction, processing, transportation and sale of hydrocarbons, renewables and other natural resources. Our clients include small and large entities, major and independent oil companies, drilling companies, oil field service providers, lenders, developers, government agencies and foreign investors.

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Austria

Bernd Rajal

Schoenherr

Dagmar Hozová

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In 2015, gross inland consumption (production + imports – exports + storage variations) of natural gas in Austria amounted to 6.9 Mtoe. Only about 1.0 Mtoe thereof was covered by domestic production of natural gas (EU Commission, DG Energy, Energy datasheets: EU 28 countries, August 2017; https://ec.europa.eu/energy/en/data-analysis/country). Austria, therefore, is dependent on the import of natural gas, mainly from Russia, Norway and Germany. By formal decision of 23 September 2016, the NRA (E-Control) approved the Coordinated Network Development Plan 2016 (CNDP 2016). The CNDP 2017 provides for 16 new projects. One of the most important projects in Austria is "BACI": the Austrian and the Czech Transmission System Operators; Gas Connect Austria GmbH (GCA); and NET4GAS (project sponsors) plan to connect their pipeline systems and create additional transportation possibilities. The length of the planned pipeline is approximately 61 km (49 km on Austrian and 12 km on Czech territory) and is planned to cross the border near the village of Reintal. GCA and NET4GAS conducted feasibility studies in line with their joint TEN-E application. Current planned completion of the project is scheduled for the end of 2020. Another important infrastructure project is the "Entry Mosonmagyaróvár" project: the cross-border point Mosonmagyaróvár connects the markets of Austria and Hungary. The physical flow direction is currently going from Austria to Hungary. The project would ensure a reverse flow from Hungary to Austria. The project is at the moment in the conceptual phase and current planning is based on market indications. This project would be a potential connection to other projects for the establishment of a Southern Corridor. The most important benefit of the project would be the diversification of routes and supply sources.

By formal decision of 20 December 2017, the NRA (E-Control) approved the Coordinated Network Development Plan 2017 (CNDP 2017). According to the extension of the capacity by remedying capacity deficiency, the CNDP 2017 grants the continuation of already approved projects and approved projects with modifications. In addition, the CNDP 2017 provides a new project "Auersthal" to set up a new central inflation system according to the DIN and API standards. This system should guarantee two separately working systems for Gas Connect Austria GmbH and OMV Exploration & Produktion GmbH, which presently share one system. Two separately working systems will lead to more efficient and secure use of inflation systems.

The Austrian gas market is currently not linked with LNG terminals outside Austria. The importation of LNG gas is nevertheless an option as some Austrian companies, together with JV partners, plan to construct new LNG infrastructure in the Adriatic region and to build, or expand, the necessary transport capacity. In 2011, the initiators of the Gate terminal (an LNG terminal in Rotterdam) signed offtake contracts with several major European energy suppliers; among which was the Austrian supply company, EconGas.

The Central European Gas Hub (CEGH), a subsidiary of OMV Gas & Power GmbH, is one of the most important natural gas trading platforms in Central Europe. Russian natural gas is transferred from that point via the Austrian pipeline system to Europe. CEGH provides hub services such as title transfer services, wheeling services or gas auctions (e.g. within the context of gas release programmes). In 2016, the Parisian-based Powernext SA and CEGH signed an agreement to jointly develop the Austrian as well as the Central and Eastern European (CEE) gas markets. For that purpose, CEGH has terminated its co-operation with Wiener Boerse AG (Vienna Stock Exchange). However, the European Commodity and Clearing AG (ECC) will remain the clearing agent and clearing house.

Transit of natural gas is carried out via the TAG and WAG pipeline systems (which are the major transmission lines in Austria), the South East Gas Pipeline (SOL), the Hungarian-Austrian Gas Pipeline (HAG), the March-Baumgarten Pipeline (MAB) and the PENTAWest pipeline. The WAG pipeline system consists of a pipeline with a DIN800 interior diameter which is enhanced by a second DIN1200 parallel pipeline for approximately 140 km and its auxiliary equipment (metering and control stations, slide gate valve station, etc.). WAG runs from Baumgarten an der March on the Austrian-Slovak border, through Lower Austria and Upper Austria to Oberkappel on the border with Germany. WAG is operated by GCA (formerly OMV Gas GmbH). The TAG pipeline comprises three parallel pipelines and the auxiliary equipment for each, including compressor stations and exit/entry points. The nominal diameters (DN) of the pipelines are between 900 mm and 1,200 mm. TAG runs from Baumgarten an der March on the Austrian-Slovak border, through Lower Austria, Burgenland, Styria and Carinthia, and on to Arnoldstein on the border between Austria and Italy. TAG is owned and operated by Trans Austria Gasleitung GmbH which is a joint venture by the Italian TSO Snam and GCA. Both GCA and Trans Austria Gasleitung GmbH have been certified by E-Control as transmission system operators

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under the ITO model. Distribution lines are operated by several regional and municipal Distribution System Operators (DSOs).

EconGas is the dominant supplier on the market for delivery of local re-distributors and on the wholesale supply market. Customers of EconGas are industrial customers with an annual natural gas consumption exceeding 500,000 cubic metres and power plants. Markets for supply of retail customers (customers with annual natural gas consumption of up to 500,000 cubic metres) are divided into several geographical areas, which are deemed identical to the distribution grids.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

The Austrian energy supply is based on a balanced mix of energy sources. In the long run, the importance of fossil energy sources has been declining in favour of renewable energy sources. This trend is also true for gas consumption; however, it is slightly less distinct. While the share of gas (mixed gas and natural gas) in 2015 was 20.3 per cent of gross inland energy consumption, it slightly increased to 20.9 per cent in 2016 (Federal Ministry of Science, Research and Economics, Development, Data of the Energy Industry 2016). Nevertheless, the share of fossil energy sources in Austria's energy portfolio (imports, domestic production and storage) is still very high.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Domestic natural gas production is performed by OMV and RAG. Only about 2 per cent of gross domestic consumption may be covered by domestic production of natural gas (see question 1.1 above). In 2013, Austrian re-distributors imported gas quantities from Russia (*ca*. 82.2 per cent), other countries like Germany and Norway (17.8 per cent; Federal Ministry of Economy, Family and Youth, Energy Strategy 2015). In 2016, net imports amounted to 497.365 GWh of natural gas. In 2016, more than 80 per cent of all physical gas imports were re-exported. (www.e-control.at, Market Report 2017.)

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

In 2014, the production output amounted to 121 million cubic metres, whereas the OMV share of the volume was 80.8 per cent, while RAG's share amounted to 19.2 per cent. LNG is not exported from Austria (Federal Ministry of Science, Research and Economics, Energy Status 2016). There is no publicly available data on the share of gas which is exported from Austria to other countries.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

The two companies engaged in the exploration and production of oil in Austria are OMV and RAG. The only oil refinery in Austria is located in Schwechat and is operated by OMV.

Austria is considered a transit country for crude oil. There are two main oil pipelines crossing the Austrian territory. Via the Trans-Alpine Pipeline (Transalpine Ölleitung – TAL), oil is transported from the Port of Trieste to Austria. Close to the Italian-Austrian border, the Adriatic Sea-Vienna pipeline (Adria-Wien Pipeline – AWP) branches off and pumps the imported crude oil intended for the domestic market from Trieste directly to the refinery in Schwechat. In 2013, 19 per cent of the crude oil transported via the TAL was imported to the Austrian market; the remaining 81 per cent was transited through to Germany (75 per cent) and the Czech Republic (6 per cent). In addition to TAL and AWP, there are two more crude oil pipelines. The GSU ships domestically produced oil to the refinery, while via the AWP-Lannach pipeline, oil is shipped to the strategic depot in Lannach.

The TAL is currently owned by a consortium of eight oil companies, including OMV Refining & Marketing GmbH (25 per cent), Shell Austria GmbH (15 per cent), Shell Deutschland Oil GmbH (4 per cent), Philipps 66 GmbH (3 per cent), TOTAL SA (2 per cent), Exxon Mobil Central Europe Holding GmbH (6 per cent), Ruhr Oel (10.8 per cent), Eni Deutschland GmbH (10 per cent), BP (9 per cent), MERO s.a. (5 per cent) and C-Blue Limited (10 per cent). In Austria, the operator of the pipeline is the Transalpine Ölleitung in Österreich GmbH. The AWP is operated by the Adria-Wien Pipeline GmbH which is a 100 per cent subsidiary of OMV Refining & Marketing GmbH and Austria's largest oil stockholding company ELG (Erdöl-Lagergesellschaft GmbH), whose shareholders are OMV (55.6 per cent), BP Europa SE (23.1 per cent), Shell Austria (16.7 per cent) and Eni Austria (4.6 per cent). ELG operates about 40 depots throughout the country.

OMV's refinery in Schwechat is Austria's sole refinery, which supplies about 60 per cent of the domestic oil consumption. The construction of a pipeline linking MOLs refinery in Bratislava (Slovakia) with the OMV refinery in Schwechat has been planned for a long time already; however, due to heated debates on the Slovakian track it has been postponed several times. In December 2017, the Slovak Economy Ministry presented a statement about the status of the working activities and the further procedure to the Slovakian Government. The main issue of the debate between the Slovak Economy Ministry (in co-operation with BSP Bratislava – Schwechat Pipeline GmbH) and the capital city of Bratislava is still the decision about the so-called city corridor going through Bratislava as the best route. The capital city of Bratislava as well as the whole Bratislava region and interested civil organisations are against the route going under the city part of Petrzalka. In addition, a project to link the Druzhba crude pipeline system via Bratislava to Vienna is planned, but is heavily debated.

The main distribution terminal is located in the OMV storage facility at Lobau. The oil products are delivered from Lobau by rail, along the Danube or on the road.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

As stated in question 2.1, oil and oil products still account for almost 40 per cent of the energy requirements of Austria. Total domestic oil consumption in 2013 amounted to 9.84 million tons, which is 3.1 per cent more than in the previous year. This figure includes consumption of petroleum products ranging from liquid gas to petrol, kerosene, gas oils, fuel oils, lubricants and bitumen (excluding petroleum products used for the petrochemical industry) (Eurostat). The remaining 89 per cent of processed oil stems from abroad. Crude oil imports in 2013 amounted to 7.83 million tons and the main suppliers were Kazakhstan and Nigeria. Libya was still the second-biggest importer of crude oil in 2010; however, due to the "Arab Spring", the imports declined to about one-third. Libyan production resumed at the end of 2011 and increased steadily in 2012.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

In 2014, the total domestic oil production (including LNG) amounted

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to 0.93 Mio tons. In total, approximately 7.7 per cent of the Austrian oil demand was covered by domestic crude oil production in 2011.

2.4 To what extent is your jurisdiction's oil production exported?

Crude oil produced in Austria is directly transported to OMV's oil refinery in Schwechat. Therefore, crude oil is not exported directly. However, petroleum products made of refined oil in the amount of 2.45 million tons are exported from Austria. Exact figures on which exact products are exported to which country are not available.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

According to the Austrian federal system, exploration and production of oil and natural gas is regulated by the federal legislator in the Mineral Resource Act ("*Mineralrohstoffgesetz* – MinroG", Federal Law Gazette I 1999/184, as amended). This act is valid for Austria as a whole and does not only regulate the exploration and production of oil and natural gas, but also the search and exploration of geological structures which can be used as storage facilities. Additionally, the act contains provisions concerning the underground storage of natural gas without tanks and the purification of stored natural gas. An Environmental Impact Assessment (EIA) has to be conducted when the exploration of oil or natural gas exceeds 500,000 m³/d (reduced thresholds of 250,000 m³/d applying to exploration fields located in a special protected area). The EIA approval, issued under the EIA Act, replaces the approval under the MinroG.

On an administrative level, the competent authorities are the Federal Ministry of Science, Research and Economy and, in case an EIA is required, the Government of the State is concerned ("*Landesregierung*"). Applicants can introduce remedies against decisions of the Federal Ministry of Science, Research and Economy with the Constitutional and also the Administrative Court. The EIA decision, issued by the State Government, can be repealed with the Federal Administrative Court ("*Bundesverwaltungsgericht*") and thereafter with the Constitutional and Administrative Court.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Oil and natural gas are considered federal State-owned mineral resources which are in possession of the Austrian Federal State (sec. 1 no. 10 MinroG). Therefore, the Austrian Federal State has the right to search, explore and produce oil and natural gas (sec. 68 para. 1 MinroG). The same is valid for the search of hydrocarbon-bearing geological structures which shall be used as storage for oil or natural gas. The Federal State is authorised to transfer the exercise of these rights to individuals or legal entities and also groups of persons based on commercial law, which dispose of necessary technical and financial means for the establishment and operation of such mining activities (sec. 69 para. 1 MinroG). The transfer of these rights is stipulated by contract governed by civil law. Therein general rights and obligations and also the consideration for the transfer of such rights, e.g. appropriate remuneration or interest payments for the used area, are determined. Such contracts will be concluded by the Federal Ministry of Science, Research and Economy in consultation with the Federal Minister of Finance. Civil courts are competent to adjust legal differences. The search, exploration of, and storage in non-hydrocarbon-bearing geological structures, which shall be used as storage for oil or natural gas, is bound on an approval of the competent authority. Such approval has to be granted to individuals, but also to legal persons and groups of persons based on commercial law. In contrast to the above, the transfer of the exercise of rights is not possible in order to prevent malpractice; however, the transfer of the approval is possible, but has to be notified to the authority.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The search, exploration and production of oil and natural gas and the search of geological structures which shall be used as storage depend on work plans. Work plans shall provide, e.g., information concerning the purpose, scope, mode and time of work and also safety measures and the names of the responsible persons.

See question 3.2 with regard to the search, exploration of and storage in non-hydrocarbon-bearing geological structures to be used as storage for oil or natural gas. The mining beneficiary has to notify the set-up of a mining establishment or an independent section of a mining establishment within the authority's correct period of time to the authority. According to sec. 119 para. 1 MinroG, an authorisation is required for the setting up or construction of mining facilities on the surface, in tunnels, mine shafts and the drilling of a drill hole and probes of more than 300m in depth, for the purpose of mining activities which start on the surface. A mining facility is defined as an artificial independent local object which is used for the search, production, purification in operational connection with the search and production of natural gas, and also the search and exploration of geological structures used for the underground storage of natural gas without tanks and the operational purification in connection with storage. An authorisation for a mining facility can only be granted, if: (i) it is constructed (set-up) on the property of the applicant, or on the property of another person with the owner's consent, or on the basis of a legally-binding decision of the authority (sec. 148 *et seq*. MinroG); (ii) according to the best available technology, avoidable emissions do not exist; (iii) on the basis of medical or other sciences which come into consideration, life or the health of persons is not endangered and no unreasonable disturbance of persons exists; (iv) it is not expected that the property of the applicant which is not committed to use will be endangered and that there will not be any damage of the environment and water; and (v) the operation of the mining facility does not produce any waste which can be avoided or is not justifiable according to the best available technology. Produced waste must be disposed of in proper form if it cannot be avoided or recycled economically. Additionally, public interests have to be taken into consideration. The authority has the power to impose obligations, terms and conditions and limitations in order to grant an authorisation. Generally, there is no operating approval required (see sec. 119 para. 8 MinroG).

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3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Generally, OMV and RAG carry out oil and natural gas development activities in Austria. Currently, the Austrian Federal State, namely the Austrian Industry Holding AG (*Osterreichische Industrie Holding AG* – OIAG), has a stake of 31.5 per cent in OMV. Different Austrian States have an indirect holding in the RAG. The States' interests have been reduced in recent years.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

As stated above (see question 3.2), the exercise of specific rights in connection with oil and natural gas development (production) is transferred by contract (sec. 69 para. 1 MinroG); this is done against payment of an appropriate consideration. Therefore, the contracting party has to pay:

(i) an area interest for the search for oil or natural gas and the search and exploration for hydrocarbon-bearing geological structures to be used as storage;

(ii) a field interest and production interest for the production including the right to acquire oil or natural gas; and

(iii) a storage interest for the storage of oil or natural gas in hydrocarbon-bearing geological structures.

Sec. 69 MinroG regulates the calculation of the production interest. Under certain conditions (economic reasons), a liberation from the area, field, production and storage interest is possible and is regulated in a special ordinance based on sec. 69 para. 1 MinroG.

3.6 Are there any restrictions on the export of production?

Austrian law does not provide special restrictions on the export of oil or natural gas production. In the event of a crisis, certain measures (including export restrictions) can be taken on the basis of the Energy Steering Act 2012 ("*Energielenkungsgesetz*", Federal Law Gazette 2013/41).

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

No specific currency exchange restrictions or restrictions on the transfer of funds derived from production out of the jurisdiction can be determined in Austrian law.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The transfer or disposal of specific oil or natural gas development rights (search, exploration and production of oil and natural gas and the search for hydrocarbon-bearing geological structures and storage therein) can only take place with the consent of the competent Federal Minister (see question 3.2). The authorisation to search and explore non-hydrocarbon-bearing geological structures, which shall be used as storage, as well as the storage therein, can be transferred by contract; it has to be notified and verified to the authority. The authority has to authorise the transfer of the storage right, if the acquirer disposes of necessary technical and financial means for the storage in such structures.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

According to sec. 69 para. 1 MinroG, participants are obliged to dispose of necessary technical and financial means for the establishment and operation of mining activities. Therefore, securities or guarantees in relation to oil and natural gas development are stipulated in civil contracts with the applicants. Existing contracts are not disclosed to the public. In case the development activities are linked to the operation of landfills, securities or guarantees for potential restoration of the landfill have to be provided to the competent authority.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

There are no special regulations in connection with the pledge for security or the booking for accounting purposes of rights to develop oil or natural gas under the Austrian law; such regulations may be stipulated in the civil contract with the competent Federal Minister.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Apart from authorisations based on the Austrian Mineral Resource Act (see question 3.3), several other authorisations (of different authorities) may be required, depending on the specific project. Therefore authorisations, e.g. according to the Nature Conservation Act or Water Rights Act, may be required. If a specific project is subject to an Environmental Impact Assessment (EIA), the competent authority issues a single decision under the EIA Act, covering all necessary licences ("one-stop shop"); see question 3.1.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

According to sec. 119 para. 14 MinroG, the abandonment of a mining facility has to be notified to the authority. This is not required if the abandonment of a mining facility has been indicated to the authority in connection with a closure plan. Such closure plan has to be authorised by the authority. The authority is empowered to prescribe safety measures.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The storage of natural gas is carried out by the Crude Oil Search Corporation ("*Rohoel Aufsuchungs AG* – RAG") and OMV Gas Storage GmbH. Natural gas is stored in hydrocarbon-bearing geological structures; the storage of natural gas in non-hydrocarbon-bearing geological structures is possible. According to sec. 97

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of the GWG 2011, storage undertakings have to grant access to storage facilities to producers, natural gas traders and suppliers domiciled in the EU (parties entitled to storage access) under non-discriminatory and transparent conditions. The storage undertaking has to stipulate storage utilisation charges on a non-discriminatory basis. The principles on which the storage charge is calculated have to be published once a year and after every change thereof (sec. 99 para. 1 GWG 2011). The access to storage can be refused under certain conditions, e.g. if access is economically unreasonable, in the event of failure conditions or a lack of storage capacities. The party seeking access to storage can file an application with the regulatory authority (E-Control), if access to storage is refused. E-Control has to find whether the prerequisites for refusal of access apply (within one month). If the authority finds out that the right to storage access has been violated, access has to be granted immediately upon service of the decision.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

The GWG 2011 provides for the setting up of a virtual trading point that can be used, *inter alia*, for cross-border trading. The virtual trading point is a notional point in a market area at which market participants can trade natural gas even without having the right to system access for the market area. Access to the virtual trading point shall be subject to the operational rules of the market area manager and the transmission system operators, in line with the market rules. The virtual trading point is not a physical entry or exit point, but enables natural gas buyers and sellers to purchase and sell natural gas without the need to book capacity. The operator of the virtual trading point as designated by the market area manager has to be independent, especially from the vertically integrated natural gas undertaking, in terms of its legal form, organisation and its decision-making power.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

According to the Oil Stockholding Act ("*Erdölbevorratungsgesetz* – EBG"), oil importers have to report their import activities to the Federal Ministry of Science, Research and Economy (BMWFW). If petroleum from other EU Member States is brought into the geographical area of application for commercial purposes or by mail order, a declaration as specified in the EBG shall be lodged with the competent customs office (together with accompanying documents required by the Petroleum Excise Act ("*Mineralölsteuergesetz*")). The BMWFW is competent to verify the completeness and accuracy of the imported quantities of oil and oil products as registered by the importer. As of 1 April of each year until 31 March of the following year, oil importers have to keep an emergency reserve of 25 per cent of their net imports of the previous year in domestic stock.

The transport of fuel oils in main or reserve tanks of vehicles is not considered import or export in accordance with the EBG.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

As regards ownership of transportation pipelines and storage facilities, see questions 1.1 and 3.2. Regulations on the operation of transportation pipelines and storage facilities for natural gas can be found in the GWG 2011. Under the former GWG, the Austrian transmission and distribution grid was divided into three control areas. Under the new GWG 2011, the transmission and distribution grid is divided in three market areas (East, Tyrol and Vorarlberg), within which a market area manager, a distribution area manager and a clearing and settlement agent are entrusted with providing system services. The market area manager shall be designated by the transmission network operators. The market area manager shall have, *inter alia*, the following responsibilities: (i) to ensure the establishment of non-discriminatory access to the virtual trading point; (ii) to manage the balance groups which are active in the market area; (iii) to coordinate system operations and the use of linepack, as well as the use of physical balancing energy together with the market area's distribution area manager, mainly via the virtual trading point; (iv) to establish a uniform methodology for the calculation and announcement of capacity at the entry/exit points of the market area's transmission network; (v) to organise the establishment and operation of the online platform for offering capacity; (vi) on the basis of a variety of load-flow scenarios and together with the transmission system operators and the distribution area manager, to draw up a common forecast of the capacity need and utilisation in the market area's transmission network over the next 10 years; (vii) to draw up a coordinated network development plan; (viii) to coordinate measures to overcome physical congestions with the distribution area manager, the system operators and storage system operators in the market area; and (ix) to coordinate the nomination procedure for the transmission system, including the exchange of nominations with the operator of the virtual trading point. Under the new GWG 2011, transit of natural gas is no longer outside the market area (control area), i.e. the pipe-in-pipe system has been abolished. In line with this, transit of natural gas is subject to the same regulations as transport for domestic supply. Network users have to be a member of a balance group or have to establish their own balance group. A balance group representative bears the responsibility for the balance group. He has the obligation to develop schedules and transfer them to the clearing and settlement agent and control area manager. Natural gas storage facilities are operated by RAG and GCA. Natural gas is stored in hydrocarbon-bearing geological structures. Storage undertakings are obliged to grant access to their storage facilities to parties entitled to storage access (producers, natural gas traders and suppliers domiciled in the European Union) at non-discriminatory and transparent conditions. Storage utilisation charges have to be stipulated on a non-discriminatory and cost-oriented basis. Access can be denied under certain conditions (sec. 97 para. 2 GWG 2011).

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

According to the law, the construction, expansion, fundamental changes and the operation of natural gas pipelines are generally

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bound to an authorisation of the authority (see sec. 148 GWG 2011). The authority has power to examine life, health, real rights, technical (safety) and environmental aspects (sec. 135 GWG 2011). The competent authority must be notified of any completion or permanent shutdown. Generally, natural gas pipelines can be operated after this notification. Depending on the specific project, several other authorisations and approvals may be required (e.g. the Nature Conservation Act). If a specific project is subject to an EIA, the competent authority issues a single decision under the EIA Act, covering all necessary authorisations ("one-stop-shop"). The operation of a transport pipeline is subject to licensing (sec. 119 GWG). In general, the TSO has to comply with one of the unbundling models set out in the Gas Directive (OU, ISO, ITO or ITO+). Gas storage pipes and spherical gas storage tanks shall require a licence under the GWG 2011; gas storage facilities are subject to the approval requirements of the MinroG.

As regards the construction and operation of oil pipelines and associated infrastructure, the Pipeline Act ("*Rohrleitungsgesetz*") applies. According to sec. 3 of the Pipeline Act, as a general rule, the transportation of goods via a pipeline, as well as the construction and operation of a pipeline, is subject to a concession issued by the governor. In case the pipeline crosses more than one State or the national border, the Federal Minister of Research, Science and Economy is the competent authority. Furthermore, a permit for the construction and operation of the pipeline has to be obtained (sec. 17 Pipeline Act). Such permit is granted on the basis of a technical construction plan submitted by the project developer. In addition to the permit under the Pipeline Act, further regulatory permits (e.g. in accordance with the Water Act or Waste Management Act, etc.) may have to be obtained from the respective competent authorities.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

According to sec. 144 para. 1 GWG 2011, the authority shall authorise, upon application, the temporary utilisation of properties belonging to third parties, with a view to undertaking preliminary works in connection with the construction, extension or alteration of a natural gas pipeline system. The application shall state the nature and duration of the intended preliminary work with a work plan attached. The applicant is only legally entitled to obtain such a decision if the preliminary work begins within one year of the application being filed. The party authorised to carry out preliminary work has to duly compensate the owners of the properties concerned, any parties who have a right *in rem* in these properties (except mortgage creditors) and any parties who hold mining licences for any restrictions they had at the time when the permit was granted (see further sec. 144 para. 9 GWG 2011). Property owners and any other parties who have a right *in rem* in a property may be deprived of, or restricted in, these property rights, provided that this is required with a view to construct a pipeline (transmission or distribution line) and that it is in the public interest to do so. A public interest shall be deemed to exist if provision has been made for such natural gas pipeline facility in the long-term plan or the network development plan. In such a case, the regulatory authority (E-Control) shall confirm the existence of a public interest by official decision. Where a natural gas pipeline facility is not included in the long-term plan or network development plan, a public interest shall be deemed to exist if the construction of such facility is necessary to achieve the objectives of the GWG 2011. For natural gas line facilities of a pressure range up to, and including, 0.6 MPa, private land may be expropriated only if no public land is available in the area concerned or if the natural gas undertaking cannot, for economic reasons, be reasonably expected to use public land.

For the construction of oil pipelines, the Pipeline Act provides for the right of the project developer to access foreign land in order to conduct preliminary studies for the preparation of the project (sec. 7 para. 1 Pipeline Act). Furthermore, the authority shall, upon application by the project developer, pronounce the expropriation of a property, if the permanent positioning of the pipeline at a certain location is required either for technical reasons or for reasons of disproportional costs for an alternative routing of the pipeline. Expropriation may include easement rights or the transfer of the property to the project developer. However, the transfer of the property shall be a measure of last resort (sec. 27 Pipeline Act).

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

The system operator operating the system to which the customer wishes to be connected is obliged to grant non-discriminating access under approved GTC, as well as regulated tariffs (see in detail sec. 27 *et seq*. and sec. 58 *et seq*. GWG 2011). In the event that the application for access also concerns a natural gas line upstream of the relevant distribution system, the system operator is obliged to pass on promptly the application to the distribution area manager for further action.

For this purpose, the natural gas undertakings concerned shall enter into contracts under civil law for the benefit of the party entitled to system access. The line capacity currently used for the customer in the network up to the virtual trading point shall continue to be available to the customer in the event of a supplier switch or supply by several suppliers. In the latter case, the current supplier shall make available that part of the capacity currently used for the customer that is needed by the second supplier for the partial supply of the customer. Imbalance charges relating to customers with several suppliers shall be settled in the balance group to which the customer's metering point is assigned.

Unlike in the gas sector, access to oil pipelines is not regulated. Access to the central stockholding entity Erdöllager-Gesellschaft GmbH (CSE) is regulated under the Oil Stockholding Act. In accordance with sec. 8 para. 5 of the Oil Stockholding Act, the Federal Minister of Research, Science and Economy shall, by order, establish a tariff of maximum charges per 1,000 crude oil units for the assumption of stockholding obligations (currently the tariff amounts to EUR 50.20 ex. value-added tax). The CSE shall conclude stockholding contracts, in accordance with these charges and general terms and conditions, with any compulsory stockholder offering to assume stockholding obligations as required by the Oil Stockholding Act.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The Austrian natural gas transportation network is disconnected and consists of three market areas. Transportation of natural gas between different control areas, e.g. from the Eastern part of Austria to Tyrol, is only possible by using foreign networks (e.g., via Germany). A market area manager is established for each of the market areas. For responsibilities of the market area manager, see question 6.1. The TSOs are obliged to co-operate with other system operators. For instance, they have to exchange information and data in order to set up a long-term network development plan. Moreover, system operators are obliged to conclude uniform interconnection point agreements with each other for all interconnection points

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between their systems. Such interconnection point agreements at interconnection points shall be concluded in consultation with, and following, the specifications of the market area manager and the distribution area manager, as applicable. The same shall apply for interconnection point agreements with system operators in other countries and the operators of storage or production facilities.

As stated in question 2.1, there are two main pipelines crossing the Austrian territory: the TAL, via which oil is transited through from Italy to Germany and the Czech Republic; as well as the AWP which branches off the TAL and transports oil from the Austrian-Italian border to the refinery in Schwechat.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

As stated above, the system operator operating the system to which the customer wishes to be connected is obliged to grant non-discriminatory access under approved GTC and regulated tariffs. The regulatory authority (E-Control) can be appealed if the right of access is damaged. Access may be denied by the system operator under certain conditions, e.g. extraordinary system conditions, insufficient system capacity or insufficient interconnection of systems. The refusal has to be notified in writing (sec. 33 GWG 2011). Where system access for transports in the distribution system is refused due to lacking capacities, the party entitled to system access shall have the possibility to file an application for capacity expansion. The distribution area manager shall take due account of the capacity need indicated in such application when drawing up the long-term plan. Capacity expansion applications shall be approved if certain conditions are met. Costs deriving from capacity expansion are allocated to the users of the grids via the regulated transportation tariffs. The regulated tariffs are based on the allowed costs of the system operators (to be calculated in accordance with chapter 5 of the GWG 2011).

Unlike in the gas sector, access to oil pipelines is not regulated.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

GTC for access to the grid have to be approved *ex ante* by the regulatory authority, which also sets the tariffs for access to the domestic transport system. Tariffs are paid by the end-consumers ("postage stamp tariff"). The tariffs for transmission system operators shall be calculated by applying a methodology which is subject to approval by the regulatory authority (E-Control) by official decision, and must comply with the requisites of Article 13 Regulation (EC) No. 715/2009. Upon request of E-Control, the methodology shall be adjusted or redesigned. The tariffs resulting from the application of the approved methodology are enacted by the ordinance of the regulatory authority and are published on the internet.

Unlike in the gas sector, the terms for transportation of oil are not regulated. The parties are free to agree on such terms in contractual agreements.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The existing Austrian transit pipelines are (at least partly) owned and operated by GCA, a subsidiary of OMV (51%) and the consortium consisting of Allianz and Snam S.p.A. (49%) (see question 14.1). Domestic transmission and distribution networks are owned and operated by GCA and Trans Austria Gasleitung GmbH as TSOs and various DSOs (see question 1.1). Domestic transmission and distribution networks are subject to regulated third-party access (TPA), which means that GTC are approved *ex ante* and tariffs are regulated.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

A licence from the regulatory authority (E-Control) is required to operate a distribution network and has to be granted if certain licence conditions are fulfilled (e.g. third-party liability insurance). The authority may impose obligations and terms or grant the authorisation temporarily (sec. 43 GWG 2011). DSOs are required to appoint an individual as technical director in charge of managing and supervising the operation of the system before the initial operation. Additionally, the operator may appoint a managing director to carry out its function (compare sec. 46 GWG 2011). The managing director is accountable to the authority with regard to compliance with the provision of the GWG 2011. The DSO has to notify the appointment of these two persons to the authority.

7.3 How is access to the natural gas distribution network organised?

The DSO operating the system to which the customer wishes to be connected is obliged to grant non-discriminating access under approved GTC and regulated tariffs. DSOs are obliged to enter into private-law contracts with consumers on the connection to the natural gas distribution system and system utilisation under approved GTC within their distribution area (compare sections 27 and 58 GWG 2011).

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Access to the distribution system may be denied by the DSO under certain conditions, as provided by the law. The regulatory authority (E-Control) can be appealed if the right of access is damaged. DSOs are obliged to enter into private law contracts with consumers on the connection to the natural gas distribution system and utilisation under the GTC within their distribution area (general obligation to connect). The system user's facility has principally to be connected to the system at a technically suitable point, with due regard to the economic interests of the system user. The general obligation to connect shall not apply if the operator of the distribution system cannot with any economic reasonability be expected to make an individual connection, considering the interests of all its customers.

If no agreement can be achieved on whether or not a systems operator is obliged to connect a consumer, the provincial governor will decide upon application of either party. Compare also question 6.6 to insufficient system capacity or insufficient interconnection.

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7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

According to sec. 72 GWG 2011, the following tariffs for the usage of the distribution networks apply:

(i) a system utilisation charge;
(ii) a system admission charge;
(iii) a system provision charge;
(iv) a metering charge; and
(v) supplementary service charges.

The regulatory authority (E-Control) shall set the distribution system charges listed above under (i), (iii), (iv) and (v), with the charges under (i), (iii) and (v) being fixed rates, by ordinance. For the charge under (iv), a ceiling shall be set. The tariffs for the transmission system charges listed under (i) to (iii) at the entry and exit points concerned shall be determined by applying a methodology to be approved by E-Control upon a proposal by the transmission system operators, and shall be enacted by ordinance.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

There are no restrictions or limitations in relation to acquiring an interest in a natural gas utility, or the transfer of assets forming part of the distribution network.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

According to the GWG 2011, natural gas traders are natural or legal persons buying or selling natural gas without carrying out the function of transmission or distribution within or outside the system in which such a natural gas trader is established. Natural gas traders buying or selling natural gas for customers in the federal territory of Austria have to notify their activities to the regulatory authority (E-Control). The conclusion of natural gas supply contracts having a duration in excess of one year and involving the purchase of a quantity of natural gas in excess of 250 million normal cubic metres per year from the territory of the European Union or from third countries, as well as their duration and the quantity of natural gas they relate to, shall be notified to the regulatory authority (E-Control). Additionally, independent natural gas traders (applicants) have to register as balance group representatives who are to be responsible for and establish a balance group in at least one of three Austrian control areas (or may join an existing balance group). Therefore, contracts with the clearing and settlement centre and the control area manager have to be concluded. September 2013 amendments to GWG 2011 introduce administrative and criminal penalties for breaches of EU Regulation No. 1227/2011 (REMIT), which came into force on 28 December 2011 in Austria. REMIT prohibits insider trading and attempted or actual market manipulation in the wholesale energy markets. According to sec. 10a GWG 2011, market participants that are obliged to publish inside information in accordance with Article 4 of EU Regulation No. 1227/2011 are additionally obliged to inform E-Control simultaneously. The European Market Infrastructure Regulation (EU Regulation No. 648/2012 of the European Parliament and of the Council of 4 July 2012 on OTC derivatives, central counter-parties (CCPs) and trade repositories (TRs) – EMIR) entered into force on 16 August 2012. If the energy trader exceeds the clearing threshold hereunder, the clearing obligation, the risk mitigation techniques and the reporting obligations must be fulfilled. Below the clearing threshold, only the reporting obligation and certain risk mitigation techniques are applicable. According to an ordinance on wholesale energy transaction data storage (Data Storage Ordinance ("*Energiegroßhandels-Transaktionsdaten-Aufbewahrungsverordnung*", Federal Law Gazette II 2012/337), energy traders are obliged to keep data of their transactions for five years. These data include the identity of the buyer/seller, the marketplace where the transaction was concluded, trading day and time of transaction, contract specifications, etc. This obligation applies for over-the-counter trading as well as for exchange trading. The data must, on demand, be provided to E-Control, to the Austrian Federal Competition Authority, and to the European Commission.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

The GWG 2011 provides for the establishment of a virtual trading point system. The virtual trading point is a notional point in a market area at which market participants can trade natural gas even without having the right to system access for the market area. The virtual trading point is not a physical entry or exit point, but enables natural gas buyers and sellers to purchase and sell natural gas without the need to book capacity, and therefore trading of unbundled products is possible; see also question 4.1.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Currently, no LNG facility in Austria exists. Some Austrian companies plan to construct such terminal in the Adriatic region as part of a JV (see also question 1.1).

9.2 What governmental authorisations are required to construct and operate LNG facilities?

LNG is not regulated under the GWG 2011.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

No, there is not.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

As there are no LNG facilities in Austria, the access to LNG terminals is not regulated.

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10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

There is no specific regulatory framework for the downstream oil sector in Austria.

However, in 2009 the Austrian Government introduced a legislative measure which restricts the ability of retailers to set pump prices. In accordance with the legal requirements, fuel station operators have to set their maximum prices in the morning and may no longer increase the prices in the course of the day. As a result of the fast increase in fuel prices, the Federal Minister of Research, Science and Economy has launched an initiative for the regulation of fuel prices before major public holidays. Accordingly, operators of fuel stations are not allowed to increase or decrease their prices for a certain period of time (usually from midday on the day before the holiday until midnight of the Sunday following the holiday).

As regards the regulatory requirements for emergency reserves, the Oil Stockholding Act stipulates that importers of crude oil, petroleum products, biofuels or feedstocks directly used to produce biofuels shall hold 25 per cent of their imports as compulsory emergency reserves from 1 April of each year until 31 March the following year.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Unlike in the gas sector, oil trading *per se* is not regulated. There are no licence or concession requirements for oil trading activities in Austria. Furthermore, there is no price regulation for oil products. Oil trading is carried out on a contractual basis.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

On an administrative level, E-Control is competent for the regulation of the gas market. The competence of other authorities being responsible for competition aspects remains unaffected. The Federal Minister of Research, Science and Economy is the highest authority. The Federal Minister is also responsible for the regulation of the search, exploration and production of oil and natural gas (ordinances, notices). The competence of other authorities being responsible for competition aspects, such as the FCA, the Federal Cartel Attorney and the Cartel Court, remain unaffected.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The regulator must observe the criteria of the Austrian Anti-Trust Act ("*Kartellgesetz*", Federal Law Gazette I 2005/61, as amended), Arts. 101 and 102 TFEU and also that of the Gas Act and Energy Regulatory Authority Act.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

According to the Energy Regulatory Authority Act ("*Energie-Control-Gesetz*" E-Control-G, Federal Law Gazette I 2010/110, as amended), one of the regulator's key tasks is to exercise market oversight. If the regulator identifies any competition violations, it has the power to instruct the respective market participant by way of official decision to act in compliance with the legal obligations. In the performance of these duties, the regulator has to seek to achieve agreement between the parties involved (see sec. 24 para. 2 E-ControlG).

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

According to the Austrian Anti-Trust Act, intended mergers generally have to be notified to the FCA if the companies involved reached, in the last year before the merger, the following turnover:

(i) worldwide, more than EUR 300 million;

(ii) in Austria, more than EUR 30 million; and

(iii) worldwide, at least two companies each with more than EUR 5 million.

In 2017, the Austrian merger control was amended, introducing a transaction value test that extends the reach of Austrian merger control. Effective from 1 November 2017, the amendment introduces additional thresholds, even if the above-listed thresholds are not met. A transaction requires a pre-merger approval in case the following four cumulative conditions are fulfilled:

- combined turnover of the undertakings exceeds EUR 300 million worldwide;
- combined turnover of the undertakings exceeds EUR 15 million in Austria;
- the "value of consideration" for the transaction exceeds EUR 200 million; and
- the target has significant activities in Austria (local nexus).

The FCA and the Federal Cartel Attorney may, within a period of four weeks from notification, either clear a merger or request the Cartel Court to examine the intended merger. The Cartel Court has to decide within a period of five months from reception of the request. The court has to interdict the merger, if it expects that the merger will lead to the creation or strengthening of a dominant position.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

According to the Foreign Trade Act ("*Außenwirtschaftsgesetz* – FTA"), acquisitions of (at least) 25 per cent, or of controlling interests in companies in specific industries, including in energy, by foreign investors (i.e. non-EEA and non-Swiss persons) require approval ("FTA approval") by Austria's Federal Minister of Science, Research and Economy ("*Bundesminister für Wissenschaft, Forschung und Wirtschaft* – BMWFW"). The FTA approval is a so-called *ex ante*

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approval and applies in case of the acquisition of energy supply and network companies. It requires the foreign investor to file for approval prior to entering into a legally binding agreement regarding such acquisition. Any acquisition entered into without required approval is invalid and, if implemented, can be unwound. FTA approval is only required for direct investments by Foreign Investors. Therefore, as a general rule, indirect investments by Foreign Investors via EU/EEA or Swiss entities are not captured by the approval regime, since EU law would not allow such investment restrictions. Accordingly, if the acquiring entity is domiciled within the EEA/EU or Switzerland, no FTA approval is required even if the acquiring entity's (indirect) shareholder is a Foreign Investor (so-called indirect investment), unless such structure was implemented and used to circumvent the approval requirement. Indirect investments might trigger an *ex officio* review procedure which aims at suspicious circumvention structures. The review procedure can be initiated by the BMWFW in exceptional cases only. It requires (i) a reasonable suspicion that the investment structure was chosen in order to circumvent the FTA approval requirement, (ii) a reasonable suspicion that the circumvention results in a threat to certain public interests, such as public order and public security, and (iii) the absence of EU provisions conflicting with the application of the FTA approval requirement.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The regulatory policy in respect of the oil and natural gas sector is especially influenced and affected by European Law, in particular by the TFEU.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

No compulsory dispute resolution procedures apply between the regulator and corporations in the oil or natural gas sector.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

The New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards was ratified in 1961, and the Convention on the Settlement of Investment Disputes between States and Nationals of Other States was ratified in 1971.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

Generally, there is no special difficulty in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

Generally, there is no difference between Austrian and foreign corporations before the law.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

As of 1 January 2017, there is a new methodology to be used for the calculation of system tariffs for gas TSOs (this is after four years of validating the preceding tariff calculation). The Gas System Charges Ordinance 2013 envisages new tariffs based on recommendations by TSOs and already contains the network code on rules regarding harmonised tariff structures for gas (TAR NC). First, the costs are based on the capacity-weighted distance (costs between the entry and exit point). These costs (entry-exit split) build the basis for the calculation system, "distance to the virtual trading point". Thereafter, fee groups are formed to enable calculability and foreseeability of fees for grid customers of the transmission system.

In 2017, E-Control published a draft of the amendment of the Gas Market Model Ordinance 2017. The amendment implements the regulatory regime set out in EU Regulation No. 2017/459, establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing EU Regulation No. 984/2013 (CAM Network Code). The amendment also contains a new provision implementing the capacity conversion service in Austria. Transmission system operators must offer network users holding mismatched unbundled firm entry or exit capacity at one side of an interconnection point a free capacity conversion service. This service applies to interconnection points where the network user had to buy bundled firm freely allocable entry or exit capacity, because the unbundled exit or entry capacity on the other side of the interconnection point offered by an adjacent transmission system operator was insufficient. The new provisions will enter into force on 15 September 2017 and 1 April 2018, respectively.

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Brazil

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Based on the information provided by the last monthly bulletin, published by the Secretariat of Oil, Natural Gas and Renewable fuels of the Ministry of Mines and Energy – MME, the main characteristics of the natural gas sector are outlined below:

- **Natural Gas Production**: 107.87 million m³/day (Associated: 84.55%; Non-associated: 23.38%).
- **Imports**: 27.00 million m³/day (Brazil-Bolivia Pipeline: 23.24 million m³/day; LNG: 3.76 million m³/day).
- **Exports**: 220.70 million m³/year (2017 – up to August).
- **Liquefaction and Export Facilities**
  - Existing Facilities:
    - (i) State of Ceará – Northeastern Region (Regasification Capacity: 7.0 million m³/day).
    - (ii) State of Rio de Janeiro Southeastern Region (Regasification Capacity: 20.0 million m³/day).
    - (iii) State of Bahia – Northeastern Region (Regasification Capacity: 14.0 million m³/day).
  - Planned Projects:
    - (i) State of Rio Grande do Sul – Southern Region (Regasification Capacity: 14 million m³/day), commercial operation in 2019.
    - (ii) State of Pernambuco – Northeastern Region (Regasification Capacity: 14.0 million m³/day), commercial operation in 2019.
    - (iii) State of Sergipe – Northeastern Region (Regasification Capacity: 14.0 million m³/day), commercial operation in 2019.
- **Receiving and Re-gasification Facilities**
  - Existing Natural Gas Processing Plants:
    - (i) State of Amazônia – Northern Region (Processing Capacity: 12.20 million m³/day).
    - (ii) State of Ceará – Northeastern Region (Processing Capacity: 0.35 million m³/day).
    - (iii) State of Rio Grande do Norte – Northeastern Region (Processing Capacity: 5.70 million m³/day).
    - (iv) State of Alagoas – Northeastern Region (Processing Capacity: 1.80 million m³/day).
    - (v) State of Sergipe – Northeastern Region (Processing Capacity: 3.00 million m³/day).
    - (vi) State of Bahia – Northeastern Region (Processing Capacity/two plants: 10.90 million m³/day).
    - (vii) State of Espírito Santo – Southeastern Region (Processing Capacity/two plants: 18.50 million m³/day).
    - (viii) State of Rio de Janeiro – Southeastern Region (Processing Capacity/two plants: 20.90 million m³/day).
    - (ix) State of São Paulo – Southeastern Region (Processing Capacity/two plants: 22.30 million m³/day).
  - Planned Natural Gas Processing Plants:
    - (i) State of Rio de Janeiro – Southeastern Region (Processing Capacity: 21 million m³/day), commercial operation until 2020.
  - Existing Re-gasification Plants:
    - (i) State of Ceará – Northeastern Region (Re-gasification Capacity: 7.0 million m³/day).
    - (ii) State of Rio de Janeiro Southeastern Region (Re-gasification Capacity: 20.0 million m³/day).
    - (iii) State of Bahia – Northeastern Region (Re-gasification Capacity: 14.0 million m³/day).
  - Planned Re-gasification Projects:
    - (i) State of Rio Grande do Sul – Southern Region (Re-gasification Capacity: 14 million m³/day), commercial operation in 2019.
    - (ii) State of Pernambuco – Northeastern Region (Re-gasification Capacity: 14.0 million m³/day), commercial operation in 2019.
    - (iii) State of Sergipe – Northeastern Region (Re-gasification Capacity: 14.0 million m³/day), commercial operation in 2019.
- **Natural Gas Pipeline Transportation**
  - (i) Existing Transportation Network: 9,409.00 km (2016).
  - (ii) Existing Distribution Network: 31,807.00 km (2016).
  - (iii) Planned Transportation/Distribution Projects: 4,153.60 km, commercial operation between 2017–2021.
- **Natural Gas Storage**
  - Three Existing Terminals:
    - (i) State of Ceará – Northeastern Region (Storage Capacity: 127,000.00 m³/LNG).

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(ii) State of Rio de Janeiro Southeastern Region (Storage Capacity: 171,000.00 m³/LNG).

(iii) State of Bahia – Northeastern Region (Storage Capacity: 136,000.00 m³/LNG).

- **Commodity Sales and Trading:** Trading volume – 69.035 million m³/day (average – July 2017).

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Pursuant to ANEEL (National Agency of Electric Energy) data, Brazil's energy requirements are met with renewable and non-renewable sources. Natural gas corresponds to 13.77% of the domestic energy supply. Other sources supply the energy demand as follows: biomass (8.85%); eolic (7.2324%); fossil (8.54%, natural gas not included); hydric (61.02%); nuclear (1.21%); solar (0.25%); and importation (4.98%).

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Brazil's natural gas requirements are met through both domestic and imported natural gas production. Domestic natural gas production supplies 59.1% of total demand. Imported natural gas corresponds to the remaining 40.9% of the domestic energy supply. Imported natural gas is provided by the following countries: (i) Bolivia (77.8%); and (ii) Nigeria and Qatar and others – LNG (22.2%).

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

According to art. 5 of the MME Ordinance n. 67/2010, the export of natural gas is conditioned on ensuring full supply of the domestic market. Total natural gas (LNG) exports amount to 220.70 million m³/year (2017 – up to August).

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Data from the ANP (National Oil, Gas and Biofuels Agency) shows that oil production in Brazil increased by 3.2%. Brazil is currently the tenth largest oil producer in the world, and the largest oil producer in Latin America. According to the Federal Government, incentives for competition, the strengthening of Petrobras and changes in the regulatory framework of the pre-salt were some of the measures that contributed to the increase in production.

- **Oil Production**: 918.73 million barrels (offshore: 864.04 million barrels; onshore: 54.69 million barrels; pre-salt production alone represents 372.75 million barrels).
- **Imports**: 65.18 million barrels.
- **Exports**: 291.36 million barrels.
- **Demand**: 8.8 million m³/year.
- **Oil Blocks**: 311.
- **Oil Fields**: 443.
- **Investments (Forecast 2016–2020)**: US$ 104 billion.
- **Proven Reserves**: 12.63 billion barrels (2016).

2.2 To what extent are your jurisdiction's energy requirements met using oil?

According to *The Oil, Natural Gas and Biofuels Statistical Yearbook 2017*, published by the ANP, 50% of Brazil's energy requirements are met through oil and its products.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

According to *The Oil, Natural Gas and Biofuels Statistical Yearbook 2017*, 85.3% of Brazil's oil requirements are met through domestic oil and its products (2016).

2.4 To what extent is your jurisdiction's oil production exported?

Oil production/exports: 5.4 million m³/year. Such amount is exported to the following countries: (i) China (37%); (ii) United States (23%); (iii) Chile (10%); (iv) Spain (9%); (v) India (6%); and (vi) others (15%).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Principal Legislation: Brazil's 1988 Federal Constitution – Introduced an open market strategy, allowing the Government to contract private companies to carry out activities related to oil and gas in the country.

Legislation for Exploration and Production of Oil and Natural Gas: Federal Law 9478/1997 – Adjusted Brazil's legal framework to the constitutional terms. Regulates the national energy policy, activities related to the oil and gas monopoly, creates the National Energy Policy Council (*Conselho Nacional de Política Energética* – CNPE) and the National Agency of Petroleum, Natural Gas and Biofuels (*Agência Nacional do Petróleo, Gás Natural e Biocombustíveis* – ANP) among other provisions.

The Gas Act: Federal Law 11909/2009 – Statutory framework that sought to regulate the gas industry setting forth clear rules in order to attract private investment.

Decree 7382/2010 – regulates Chapters I through VI and VIII of Federal Law 11909/2009, which deal with the conveyance of natural gas.

Pre-Salt Law: Federal Law 12351/2010 – Issued after the discovery of pre-salt. Deals with the exploration and production of oil, natural gas and other fluid hydrocarbons, under the production sharing regime, in pre-salt and strategic areas.

Law 13.365/2016: Removes the requirement that Petrobras be the sole and exclusive operator of the pre-salt exploration blocks in the production sharing regime.

State's Mineral Rights: The Federal Government owns exploration and production rights of oil, natural gas and other fluid hydrocarbons

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in the country, including onshore reserves, territorial waters, the continental shelf and exclusive economic zone. The ANP manages such rights, except as otherwise set forth under the law (art. 21, Federal Law 9478). As previously mentioned, the Constitution opened the oil and gas market, allowing the Federal Government to concede its oil and mineral rights to the private sector.

Local Content Requirements (LCR) Reforms: On March 28, 2017, the Brazilian Ministry of Industry and Foreign Trade (MDIC) published Resolution n. 1, that lowered the percentage of Brazilian-made goods and services required for oil and gas exploration and production.

Government Authorities: The National Agency of Petroleum, Natural Gas and Biofuels (ANP); the Ministry of Mines and Energy (MME); and the National Council on Energy Policy (CNPE).

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The State's mineral rights to explore oil and natural gas reserves are transferred to companies under Concessions, Authorisation or Production Sharing Agreements.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

In that way, different authorisations must be issued for different stages of oil and gas development, which can be divided into:

(i) prospecting and production of oil deposits, natural gas and other fluid hydrocarbons;

(ii) refining of domestic or foreign oil;

(iii) import and export of petroleum and basic by-products; and

(iv) maritime transport of crude petroleum of domestic origin.

According to Federal Law 9478/97, in its art. 24, concession and production sharing agreements must contain provisions outlining the existence of two phases of development of a field: exploration; and production. The exploration phase includes the activities of evaluation and possible discovery of oil or natural gas, in order to determine its commercial value. The production phase shall also include development activities.

According to ANP rules, the Minimum Exploratory Program defines that, under the concession agreements, the exploration phase may last 3 (three) to 8 (eight) years. The production phase may last 27 (twenty-seven) years. Extensions to such terms may occur under the ANP's approval, according to the provisions of the concession agreement.

ANP's Minimum Exploratory Program defines that, under the concession regime, the exploration phase may be divided into exploratory periods during which the concessionaire must develop exploratory activities of geology and geophysics, for research purposes regarding the Brazilian sedimentary basins, especially those of the acquired block.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

The Constitution's art. 177 states that the Federal Government has a monopoly on the following activities: (i) prospecting for and exploitation of deposits of petroleum and natural gas and of other fluid hydrocarbons; (ii) refining of domestic or foreign petroleum; (iii) import and export of the products and basic by-products resulting from the activities set forth in the preceding items; and (iv) ocean transportation of crude petroleum of domestic origin or of basic petroleum by-products produced in the country, as well as pipeline transportation of crude petroleum, its by-products and natural gas of any origin.

The Federal Government may contract with private enterprises for the execution of the activities described above, with due regard for the conditions set forth by law.

In addition, the Federal Government has strong involvement in the oil and gas industry, developing and controlling the activities in this sector; establishing import and export guidelines so as to meet the domestic consumption needs for petroleum and its by-products and natural gas and condensate; ensuring proper regulation and authorisation of activities related to production, import, export, storage, transport, transfer, distribution, retail and sale of biofuels; as well as issuing conformity analysis and quality certification, by inspecting them on a direct basis or by means of partnerships with other bodies of the Union, States, Federal District or Municipalities.

Additionally, the National Council on Energy Policy was created to develop strategies and guidelines for the oil and gas sector.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The State derives value from oil and natural gas development through signature bonus, royalties, special share, and payment for occupation or retention of area. The option for any one of these in particular will depend on the concession contract. However, art. 45 of Federal Law 9478/1997 states that royalties and the payment for holding or occupying the area are mandatory.

3.6 Are there any restrictions on the export of production?

Any enterprise or consortium of enterprises organised under Brazilian law, with headquarters and management in the country, may be granted authorisation by the ANP to perform oil, by-products, natural gas and condensate export activities. To that end, it must comply with statutory requirements.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Oil and gas legislation do not impose any specific currency exchange restrictions, or restrictions on the transfer of funds derived from production, although Federal Law 4,131/1962, which regulates the income of foreign capital and the remittance of national capital, sets out some requirements for currency transfer, including previous registrations with the Central Bank of Brazil.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The transfer of the concession contract with the preservation of its object and condition is allowed, as long as the new concessionaire complies with the technical, economic and legal requirements set

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forth by the ANP. Transfer of the contract may only occur upon prior and expressed authorisation by the ANP. In seeking to transfer rights, the parties must initiate a Disposal Procedure as provided for by the ANP. The legal grounds are Federal Law 9478/1997, arts. 25 and 29.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

The participants are obliged to provide guarantees upon being awarded oil and gas contracts. According to Federal Law 9478/1997, the concession contract shall have an essential clause stating which guarantees must be provided by the concessionaire regarding the performance of the contract, including as to investments agreed upon for each phase. The legal grounds are Federal Law 9478/1997, art. 43, V, and Federal Law 11909/2009, art. 21, VI.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The rights to develop oil and natural gas reserves can be pledged for security, or booked for accounting purposes under domestic law, subject to the ANP's authorisation.

In this regard, the ANP has issued an orientation, making it possible for the concessionaire to grant its oil and gas development rights, since it has the ANP's express approval.

In this orientation, the ANP restricts the range of potential acquirers of the rights, which can only be companies qualified for the development and production of oil and gas, and willing to be part of the concession contract, accepting the whole of its rights and obligations.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

In Brazil, the Federal Environmental Agency (IBAMA) is responsible for the licences and authorisations concerning large projects, such as exploration and production of oil and gas. The licences and authorisations required will depend on the project's scope and dimension. In general, the following licences may be demanded by the Government: (i) Operating Licence for Seismic Activities; (ii) Pre-Drilling Licence; (iii) Pre-Research Production Licence; (iv) Installation Licence; and (v) Operating Licence.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Federal Laws 9478/97 (art. 28, paragraph 2) and 12351/2010 (art. 32) state that in any event of termination of the concession, the concessionaire shall, at its own expense, remove the equipment and assets that are not object of reversion, and is obligated to repair or indemnify for damages arising from of its activities and undertake environmental recovery action as established by the relevant bodies.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The storage of natural gas must be performed by an enterprise or consortium of enterprises organised under Brazilian law, with headquarters and management in the country, at the entrepreneur's own risk and expense, through concession, preceded by a bidding process or authorisation. The storage of natural gas in hydrocarbon reservoirs relinquished to the Federal Government, and in other non-producing geological formations, must be the subject matter of concession for use, through a bidding process, and the exploration must be at the concessionaire's own risk and expense. The MME, or the ANP through delegation, must define the geological formations that are the object of the bidding process. The legal framework is Federal Law 11909/2009, arts. 37 and 38.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

According to Federal Law 11909/2010, any enterprise or consortium of enterprises organised under Brazilian law, with headquarters and management in the country, can obtain authorisation from the MME to carry out natural gas import/export activity. This activity of natural gas import and export must observe the guidelines set forth by the CNPE (*Conselho Nacional de Politica Energética*), in particular those related to the provisions of art. 4 of Federal Law 8176/1991.

In addition, the Brazilian Integrated Foreign Trade System (SISCOMEX) legislation must be observed with regard to registry, monitoring and control of foreign trade, through a single and computerised flow of information (Decree 660/1992).

The gas importation is subject to ANP and MME specific legislation, such as Ordinance ANP 43/1998.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

According to Federal Law 9478/1999, any enterprise or consortium of enterprises organised under Brazilian law, with headquarters and management in the country, can obtain MME authorisation to perform natural gas import/export activity. The performance of natural gas import and export must observe the guidelines established by the CNPE, in particular those related to the provisions of art. 4 of Federal Law 8176/1991.

In addition, the Brazilian Integrated Foreign Trade System (SISCOMEX) legislation must be observed with regard to registry, monitoring and control of foreign trade, through a single and computerised flow of information (Decree 660/92).

Oil importation is subject to ANP- and MME-specific legislation; as an example we can cite Ordinance ANP 147/1999 and Ordinance ANP 7/1999.

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6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

The activities related to the transportation, processing and storage of gas are regulated and inspected by the Federal Government, as the granting authority, and may be exercised by an enterprise or consortium of enterprises organised under Brazilian law, with headquarters and management in the country. Those activities must be performed under concession, preceded by a bidding process or authorisation. The ANP is the main authority responsible for regulating the sector.

According to law, the transportation network up to the city gates is composed by three types of pipelines: (i) gas production offloading pipelines; (ii) transfer gas pipelines; and (iii) transport gas pipelines. Gas production offloading pipelines are used in production facilities to provide the necessary movement of natural gas from wells to processing and treatment facilities. The transfer gas pipelines are used for the movement of produced natural gas. The transport gas pipelines execute the movement of natural gas from treatment or processing facilities to storage or other transport gas pipelines.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

To construct and operate oil and gas transportation pipelines, two main authorisations are required by the ANP according to Ordinance n. 170/1998: the Construction Authorisation; and Operation Authorisation.

The grant of these authorisations is subject to the presentation of other documents, such as an environmental licence (there are three in Brazil: Previous Licence; Construction Licence; and Operation Licence) and others able to prove the legality of the undertaking and engineering aspects.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

The Government authorities have the power of compulsory land acquisition. The tender protocol must indicate explicitly that the concessionaire must pay the indemnification due for expropriations or easements necessary to execute the agreement.

The MME may delegate to the ANP the power to declare the public utility of areas needed for the construction so they can be expropriated by the Government.

ANP Resolution 44/2011 provides the procedures and requirements for the obtainment of the declaration of public utility. Accordingly, a pipeline developer may request the ANP to declare the public utility of an area, upon the submission of an application, instructed with the clarifications and documents mentioned in the Resolution.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Any interested party may use the transport pipelines and maritime terminals, with the exception of the Liquefied Natural Gas (LNG) terminals, through proper compensation to the owner of the installations or the natural gas transport capacity, pursuant to applicable law and regulation. The use must be informed by the transporter to the ANP. The party interested in the pipeline must have an agreement with the transporter, which must be registered by the ANP. The agreement must contain information about the services that are being rendered, terms and conditions of these services, contracted transport capacities and price. See also the answer to question 6.6.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The oil and natural gas transportation pipelines can be interconnected in the same terms as the third-party regulation permits. According to ANP Resolution 35/2012, which governs the access of third parties to pipelines, the transporter may allow the integration with others or transfer the installations. As said, the party interested in having access to the pipeline must have an agreement with the transporter, subject to the rules related to third parties' access to pipelines and authorisations.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

The access of third parties to the gas pipelines is granted by art. 58 of Federal Law 11909/2009. The access must be through the hiring of the following transport services, among other ways provided for by the regulations: (i) firm, in available capacity; (ii) interruptible, in idle capacity; and (iii) extraordinary, in available capacity. Access to the gas pipelines must be first in the available capacity and only after fully hiring the right to access idle capacity is granted. Access to the firm transport service in available capacity must be through public call for tender carried out by the ANP, according to guidelines of the MME. Access to the interruptible transport services, in idle capacity, and extraordinary, in available capacity, must be pursuant to the regulations, the publicity, transparency and guarantee of access being assured to all interested parties. The assignment of capacity is authorised, construed as a transfer, in whole or in part, of the right to use the firm transport capacity hired. The ANP will regulate the capacity assignment to preserve the carrier's rights. The parties will sign an Undertaking of Access by which will be defined the costs condition according to ANP Resolutions 35/2012 and 11/2016.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

According to Federal Law 11909/2009, the parties can agree on the terms upon which the oil and/or natural gas is to be transported, by negotiating the transportation agreement terms and conditions, but

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the ANP has to approve if the agreed remuneration is in accordance with the practices of the market.

However, if the parties do not reach an agreement regarding remuneration to be applied, the ANP has the power to determine the price to be paid in the agreement.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

According to art. 25, paragraph 2 of the Brazilian Federal Constitution, the States have the power to operate, either directly or by means of concession, the local services of piped gas, as provided for by law. When conceded, the distribution is to be performed by corporations whose formation is governed by Brazilian law, with headquarters and management in the country that obtained ANP authorisation for gas distribution.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

To operate in the gas distribution sector, the concessionaire must obtain the Construction Authorisation and Operation Authorisation from the ANP. In order to obtain these authorisations, the concessionaire must present to the authority the documentation able to prove land rights to construct, enterprise legitimacy, adequacy of engineering aspects and environmental licences.

7.3 How is access to the natural gas distribution network organised?

The State distribution company will run the gas distribution services in that State during the contracted period, which is usually about 30 years. During the concession period, the company will hold exclusivity over the distribution infrastructure and the customers. If the State distribution company does not offer the capacity needed to cater to all the State customers, the free consumer, the self-producer or self-importer will be authorised to construct and implement facilities and pipelines for its own specific consumption.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Yes, the regulator can require the distributor to grant capacity and expand the system in order to accommodate new customers, depending on the contractual terms. That also can be a request from the company to the regulator. On the other hand, if the distribution facilities are constructed by the free consumer, the self-producer or self-importer, pursuant to the head paragraph of this article, the State distribution company may require that the facilities be sized in such a way as to allow other users to have their needs met, negotiating the necessary compensations with the free consumer, the self-producer or self-importer, under arbitration of the State regulating body.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

In order to purchase the gas from the distribution company, the customer must pay to the company a fee stipulated by the regulatory authority. On the other hand, to have access to the distribution network, the customer will also bear the cost, which will be defined among the parties in the contract terms.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

In general, the sale of a controlling stake must be subject to approval of the relevant authority, under penalty of termination of the concession agreement. In the oil and gas sector, the ANP requires that the new company meet the qualification specified in the bid and that this company is prepared to bear the concession contract obligations.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

According to the 1988 Federal Constitution, Brazilian States are responsible for the distribution and retail trading activities. Initially, only State-owned companies were allowed to carry out such services. In 1995, a constitutional amendment extended this right to investor-owned companies holding a concession contract awarded by State Governments. Since 2009, based on Federal Law 11909, gas trading is authorised by the ANP. Aside from State trading, the sale of natural gas takes place through contractual agreements negotiated between private parties. All private contracts are registered at the ANP. These agreements must contain a clause to resolve possible conflicts, and may even provide for an arbitration agreement. It must be incumbent upon the ANP to inform the companies of the origin or technical specifications of the reserves that will support the supply of contracted natural gas volumes.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Per Decree 7382, the authorised companies can trade "any hydrocarbon remaining in a gaseous state under normal atmospheric conditions, extracted directly from oil or gas reservoirs, the composition of which may contain wet, dry and residual gases".

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

According to ANP Resolution 52/2015, the construction, expansion and operation of product-handling facilities depend upon prior express authorisation by the ANP. These authorisations will be granted to the company, or consortium of companies that comply with the technical, economic and legal requirements established by the ANP in two (2) stages: Construction Authorisation (CA); and Operation Authorisation (OA). Only companies or consortia

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organised under Brazilian law, with headquarters and management in Brazil, will be authorised to explore for and transport natural gas.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The companies must obtain a Construction Authorisation (CA) and an Environmental Installation Licence.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Under art. 69 of Federal Law 9478/1997, fuel prices have been unregulated in Brazil since January 2002.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Art. 48 of Decree 7382 defines "operation exchange" as a form of third-party access to oil and gas transportation pipelines. Under the terms of ANP Resolution 11/2016, the transporter must inform the conditions of access to its pipelines through the Terms of Access, which contains the terms and conditions of access, including descriptions of the available transportation services and applicable rates. The resolution also states that the transporter must provide a free and public electronic platform with information on the availability, access possibilities and reference to the Terms of Access. Once these agreements are finalised, carriers must enable third-party access to existing transport infrastructure, provided there is secure operational safety, in order to allow effective competition in the production and sale of natural gas.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

According to ANP Resolution 16/2010, all oil-refining activities which cover the construction, modification, expansion of capacity and operation of oil refineries are dependent upon the prior and express authorisation of the Agency.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The ANP grants oil and gas exploration and production rights to companies or consortia based on their bids in a series of rounds. Bids must comply with economic, legal and technical stipulations specified by the ANP. While foreign companies may participate in the bidding process, winners must create a Brazilian company to carry out oil and gas exploration and production.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

According to Antitrust Brazilian Law (Federal Law 12529/2011), the governmental authority responsible for the regulation of competition aspects in general, including anti-competitive practices in the oil and gas sector, is the CADE – Administrative Council for Economic Defence.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The following acts will be considered violations to the economic order, regardless of fault, even if not achieved, according to the CADE: (i) to limit, restrain or in any way injure free competition or free initiative; (ii) to control the relevant market of goods or services; (iii) to arbitrarily increase profits; and (iv) to exercise a dominant position abusively. The following acts, among others, to the extent to which they conform to the principles set forth above, must characterise violations of the economic order: (i) to promote, obtain or influence the adoption of uniform or agreed business practices among competitors; (ii) to limit or prevent new companies from entering the market; (iii) to create difficulties for the establishment, operation or development of a competitor company or supplier, acquirer or financier of goods or services; and (iv) to prevent the access of competitors to sources of input, raw material, equipment or technology, and distribution channels, and other anti-competitive conducts.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The CADE has the power to preclude or take action in relation to anti-competitive practices. Among others, the following are the most important powers and duties of the CADE, according to Federal Law 12529/2001 in its art. 13:

(i) monitor, permanently, the business activities and practices of individuals and legal entities holding a dominant position in the relevant market of goods or services, in order to prevent violations of the economic order, and for such purposes, request necessary information and documents, while maintaining confidentiality, where necessary;

(ii) advance, in light of indications of violations of the economic order, preparatory procedures for administrative inquiries to investigate violations of the economic order;

(iii) where there is a lack of grounds to sue, dismiss the records of the administrative investigation or its preparatory procedures;

(iv) prepare and initiate administrative proceedings for the imposition of sanctions due to violations of the economic order, procedures to verify cases of concentration, administrative proceedings to analyse cases of economic concentration, and administrative proceedings to impose procedural sanctions filed for the prevention, ascertainment or repression of violations to the economic order; and

(v) upon determining violations of the economic order, submit the case to the Tribunal.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Yes, the CADE has the power to approve or disapprove these types of operation. The parties must submit to the CADE all merger transactions in which, cumulatively: (i) at least one of the groups

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involved in the transaction recorded, in the last balance sheet, annual gross sales or total sales in the country, in the year preceding the transaction, equivalent or superior to seventy-five hundred million Brazilian Reais (BRL 750,000,000.00); and (ii) at least one other group involved in the transaction recorded, in the last balance sheet, gross annual sales or total turnover in the country, in the year preceding the transaction, equivalent to or greater than seventy-five million Brazilian Reais (BRL 75,000,000.00). The control of the merger referred to above will occur prior to the transaction and must be performed within, at the latest, 240 (two hundred and forty) days as of the application protocol or amendment thereto.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

If a foreign company takes part in a bidding process for the natural gas sector, it has to provide the Brazilian authority with the following: (i) evidence of technical capacity, financial competence and legal and fiscal status pursuant to regulation issued by the ANP; (ii) its articles of incorporation/bylaws, and evidence that it is organised and regularly operational, pursuant to the laws of its country; (iii) appointment of a legal representative with the ANP, with special powers to carry out acts and assume responsibilities under the bidding process and the bid submitted; and (iv) if the company is awarded a contract, the company must set up a company under Brazilian laws, with headquarters and management in Brazil.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Once international treaties and multinational arrangements are ratified by the Brazilian Congress, they come into force and become obligatory.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Litigation in the oil and gas sector can take place in court, through arbitration or administratively. In administrative proceedings, there are specific procedures, defined by law, that have to be observed in order to resolve disputes with the Government. In this context, Decree 2953/1999 regulates the administrative procedures concerning irregularities and penalties in the oil and gas industry.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Although Brazil is not a member of ICSID, the country follows many of its rules regarding arbitration. Brazil is a signatory to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

The Government does not have immunities against litigation in the oil and gas sector. However, the private party still faces difficulties in litigating against the governmental authority, as the courts are protective of the public interest. Furthermore, considering that negotiations in the oil and gas industry involve long-term contracts and great investments, political and regulatory changes can cause an impact on the projects.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are not aware of any such cases.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Currently, Brazil is going through a new phase with the possibility of opening up opportunities for new players to enter the market.

In 2016, changes in the legislation brought by Federal Law 13365/2016 have already excluded the mandatory participation of Petrobras as operator, with a minimum participation of 30% in the pre-salt.

In 2017, the Federal Government published Decree 9,041, which regulated the preference right of Petrobras to act as operator in the consortia formed for the exploration and production of blocks to be contracted under the regime of production sharing.

In addition, adjustments in royalties have been made. The National Energy Policy Council (CNPE) published Resolution n. 17, of June 8, 2017, which establishes, among the guidelines for the ANP, the concession, based on pre-established criteria and provided that the economic benefit to the Federal Union is proven, in the ambit of the extensions of the deadlines of existing contracts, of a reduction of royalties, up to 5% (five per cent), on the incremental production generated by the new investment plan to be executed, in order to allow the extension of the lifespan, maximising the recovery factor of the fields.

New opportunities have arisen through new bidding rounds. The CNPE has approved a bidding rounds calendar. During 2017–2019, 9 (nine) new bidding rounds should occur, offering acreages

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containing a billion barrels of oil in place and creating opportunities for exploration and production companies.

The 14th round with blocks under concession regime, which already occurred on September 27, had the largest signature bonus in history: R$ 2.24 billion. The 2nd and 3rd Pre-Salt Bidding Rounds have 75% of its blocks acquired.

For the 15th and 16th bidding rounds, and for the 4th and 5th production sharing bidding rounds, blocks are being defined, and tender protocols and contracts are under development.

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Canada

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Canada is the world's fifth-largest natural gas producer in the world, behind the United States, Russia, Iran and Qatar (source: Natural Resources Canada). As of 2016, Canada has approximately 77 trillion cubic feet of proved natural gas reserves. In 2016, Canada produced a total of 15.2B cubic feet of natural gas per day, 7.9B of which was exported, and 8.3B of which was consumed domestically (source: IEA).

Canada is the United States' number one foreign supplier of natural gas, with approximately 98% of the United States' natural gas imports coming from Canada (source: EIA). For the eight years leading up to 2015, exports of natural gas from Canada to the United States have declined by 20%, as production of shale gas in the United States has driven down domestic prices, reducing the demand for natural gas imports from Canada (source: EIA). However, in 2016 Canadian imports increased by 11% (source: EIA). Western Canadian natural gas continues to compete for market share in Central Canada, where closer natural gas supplies are increasingly available from the United States.

Canada has an extensive natural gas transportation system linking the Western Canadian Sedimentary Basin to markets in Eastern North America, the Midwest and California. There are 39 natural gas pipelines that cross the Canada-United States border (source: Natural Resources Canada). More recently, export pipelines originating in Ontario have been adapted to enable bi-directional gas flow to accommodate the increase in imports of shale gas to Central Canada from the United States.

As competition from the United States' domestic supply has decreased demand for Canadian natural gas exports to the United States, Canadian natural gas companies continue to develop LNG facilities in an attempt to access new foreign natural gas markets. There are currently 16 LNG terminals proposed for development in the Province of British Columbia and approximately half of that number proposed in the East Coast Provinces of Canada.

Canada currently has a single LNG importation and regasification facility – the Canaport LNG facility in New Brunswick on Canada's Atlantic coast (the "**Canaport Facility**") – and no LNG liquefaction and export facilities.

Canada has over 820 Bcf of storage capacity, amounting to over 30% of Canada's annual natural gas demand (source: Canadian Gas Association and Natural Resources Canada). According to Natural Resources Canada, this capacity has been increasing at a rate of 5% per year for the past decade.

Canada's natural gas markets are unregulated and this has fostered the development of a sophisticated wholesale energy trading market. The Canadian and United States gas markets are integrated and operate as a single North American market. There are three major pricing points for North American natural gas. The Henry Hub in Louisiana is the pricing point for the New York Mercantile Exchange ("**NYMEX**"), while the AECO-C Hub in south-eastern Alberta and the Dawn Hub in Ontario are the primary pricing points in Canada. The retail and commercial natural gas supply in Canada is regulated to varying degrees across the country according to the respective provincial regulatory body.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Natural gas accounts for 34% of Canada's total primary energy supply ("**TPES**"), oil accounts for 35%, followed by Hydro (12%), nuclear (10%), coal (6%), and biofuels, wind, solar and geothermal comprising (6%) of TPES (source: IEA, 2016).

Natural gas supplies approximately 8% of Canada's total annual electrical energy production needs. Renewables, which includes hydro (60%), wind (4%), biofuels & waste (2%) and solar (1%) account for approximately 67%, followed by nuclear which supplies 16%, coal which supplies 8%, and oil which supplies 1% (source: IEA, 2016).

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Despite Canada's capability to meet its natural gas requirements through domestic natural gas production, Central and Eastern Canada have both increased imports of natural gas from the north-eastern United States, where an abundance of supply has driven down the price of natural gas. In 2016, approximately 82 bcm of natural gas was imported to Canada primarily from the United States, but also small amounts through the Canaport Facility (source: US EIA).

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1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Canada is the fourth-largest exporter of natural gas. In 2016, Canadian exports to the U.S. increased and were at the highest level since 2012 (source: NEB). The net volume of natural gas exported from Canada increased from the previous year by 10%, from 5.4 Bcf/d to 6.0 Bcf/d. Exports increased 11% from 7.3 Bcf/d to 8.1 Bcf/d (source: NEB).

Canada does not currently have any LNG liquefaction and export capacity. However, as of 2016, a total of approximately 293 million metric tonnes *per annum* of liquefaction capacity had been proposed for Western Canada (i.e. Pacific coast) and a further 51.5 million metric tonnes *per annum* for Eastern Canada (i.e. Atlantic coast). In 2017, several final investment decisions in respect of the most advanced of Canada's LNG projects occurred, resulting in four (4) large LNG projects being cancelled for economic reasons as further discussed in question 14.1, including the $36 billion Pacific Northwest LNG project.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Canada is the world's fourth-largest crude oil producer and ranks third in oil reserves (behind Saudi Arabia and Venezuela), with 171.4 billion barrels of estimated proven oil reserves, and of that number, 165.3 billion barrels are located in the Alberta oil sands (source: Natural Resources Canada). Canada's proximity to the United States and its stable political, legal and financial regime has resulted in significant international investment in its oil industry. Canada's oil industry includes a diverse composition of companies engaged in exploration and production, transportation, upgrading and refining.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Approximately 31% of Canada's energy demand is supplied through the consumption of oil (source: US EIA).

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Canada's oil requirements are primarily met through domestic oil production (source: US EIA). In 2016, Canada produced approximately 3.6 million barrels of oil per day, while it consumed 1.8 million barrels of oil per day (source: CAPP). Despite Canada's capability to meet its oil requirements through domestic crude oil production, in 2017, total crude oil imports averaged approximately 759,000 barrels per day (source: National Energy Board Canada, 2017).

2.4 To what extent is your jurisdiction's oil production exported?

Nearly all of Canadian exported crude oil is exported to the United States (source: Natural Resources Canada). Canada is the largest foreign supplier of crude oil to the United States (source: Natural Resources Canada). In 2016, Canada exported 3.08 million barrels of crude oil per day to the United States, which accounted for approximately 99% of Canada's total crude oil and equivalent exports (source: National Energy Board Canada, 2017).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Canada's Federal and provincial governments share jurisdiction over Canadian energy policy, as well as the legal and regulatory framework for the exploration of Canadian oil and natural gas reserves. Accordingly, there is no single energy policy or regulatory body governing the development of oil and natural gas reserves in Canada. In addition to regulating the oil and gas industry in Canada, the Federal and provincial governments are also owners of the majority of Canada's mineral rights, with the provincial governments being the major holders of mineral rights in Canada. The Federal government's ownership of mineral rights is much smaller in comparison to the provincial governments' ownership of mineral rights, with most of the Federal governments' ownership rights being made up of oil and gas rights in Canada's national parks and Aboriginal lands.

Federally owned oil and gas rights are governed by the *Canadian Petroleum Resources Act* and the *Canada Oil and Gas Operations Act*. Provincially owned oil and gas rights are governed by each province's respective legislation governing the exploration and production of oil and natural gas. The National Energy Board (the "**NEB**") is the Federal agency that handles the majority of the responsibilities regarding the regulation of interprovincial pipelines and energy development and trade, while each province has its own regulatory body with responsibility over intraprovincial projects.

Canada's Federal government has recently initiated a review of the NEB's structure, role and mandate to ensure its composition reflects regional views and has sufficient expertise in environmental science, community development and Indigenous traditional knowledge.

There are hundreds of privately owned and publicly listed companies that are engaged in the exploration and production of oil and natural gas in Canada. These companies obtain the right to explore, drill and produce oil and natural gas primarily from the provincial governments.

Although the majority of Canada's oil and natural gas is owned by the Federal and provincial governments, some oil and gas rights are held by private landowners. For example, in the province of Alberta, approximately 14% of Alberta's oil and gas rights are privately owned. Companies obtain the right to explore, drill and produce oil and natural gas from private landowners by way of a privately negotiated oil and gas lease.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The oil and natural gas rights owned by Federal and provincial governments and private individuals, as discussed in question 1.1, are transferred to participants through licences and/or leases to explore for, develop and produce oil and/or natural gas.

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Once a licence or lease is issued, a participant is entitled to explore for, develop and produce oil and natural gas in accordance with the terms of the licence or lease. At the end of the term, or upon termination of the licence or lease, the rights granted to the participant will revert to the owner who issues the licence or lease.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Authorisations in respect of different stages of development are typically addressed in the lease agreement or the licence issued by the mineral owner. In some cases, a licence may first be issued to allow a participant the opportunity to conduct certain exploration activities in order to confirm the existence of oil and natural gas reserves covered by such licence. Upon proving the existence of such oil and gas reserves, a lease for the production and development of such reserves is subsequently issued.

A typical oil and natural gas lease would include the following standard provisions: (a) a granting clause specifying the mineral rights that can be explored for and produced; (b) provisions respecting the terms of the lease; (c) royalty provisions reserving a royalty to the lessor of the lease; (d) rights of the lessee to undertake activities to continue the lease; (e) clauses addressing abandonment and reclamation obligations; and (f) liability and indemnification provisions.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Canadian Federal and provincial governments do not seek to directly participate in the development of oil and natural gas reserves. Rather, as outlined above, the governments lease their mineral rights to privately held and publicly listed oil and gas companies to explore for, develop and produce oil and natural gas.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Federal and provincial governments and private landowners derive value from their ownership of mineral rights by issuing leases to oil and gas producers, which leases include provisions (a) reserving to themselves a royalty that is calculated with respect to the volume of oil and natural gas produced from the lands, and (b) imposing an obligation on the lessee to make a prescribed annual payment when no production has been derived from the lands.

3.6 Are there any restrictions on the export of production?

Pursuant to the *National Energy Board Act* (Canada) (the "**NEB Act**"), oil or gas may not be exported without a licence issued by the NEB. Any oil or gas exporter must also otherwise be in compliance with the exportation requirements set out in the NEB Act and applicable regulations to export oil and gas production.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are generally no currency exchange restrictions or restrictions on the transfer of funds derived from production out of Canada.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

A lease issued for the development of oil and natural gas will govern the ability of a participant to transfer or dispose of its oil and natural gas development rights. With respect to Federal and provincial leases, the transfer of development rights is generally permitted and frequently occurs in Canada's oil and gas industry. Ownership changes are typically approved by and registered with the applicable provincial registrar.

With respect to leases issued by a private landowner, transfer or disposition of oil and natural gas development is generally permitted, subject to certain restrictions. A typical restriction would give the mineral rights owner the rights to withhold its consent to a transfer where the transferee may not have the financial resources or technical expertise to develop and produce the resources.

The *Investment Canada Act* includes restrictions on the sale of oil and gas rights and interests to foreign investors. See question 12.1 for a discussion of those restrictions.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Depending on the jurisdiction, participants who do not have sufficient capital resources may be required to provide a form of security in relation to oil and natural gas development, particularly in relation to abandonment and reclamation obligations. For example, the Alberta Energy Regulator (the "**AER**") requires a licensee to maintain a ratio of deemed assets to deemed liabilities (known as a Liability Management Rating or "**LMR**") above 1.0. If a licensee's LMR falls below the 1.0 threshold, the licensee is required to provide a security deposit equal to the difference between the licensee's deemed liabilities and deemed assets.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

An oil and gas lease is considered to be a form of intangible personal property, and thus can generally be pledged for security. Oil and natural gas reserves can be booked for accounting purposes. General rules for booking reserves are found in the Canadian Oil and Gas Evaluation Handbook.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

There is a vast amount of legislation and regulations that apply to the development of oil and natural gas reserves. Perhaps the most

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significant legislation outside of exploratory and production regimes concerns the protection of the environment and the health and safety of persons actively engaged in the production of oil and natural gas. The Federal and provincial governments share responsibility for the protection of the environment and for occupational health and safety standards in Canada. The *Canadian Environmental Protection Act* is the primary Federal legislation governing the protection of the environment. Each province has also enacted province-specific legislation concerning environmental protection. Environmental protection legislation in Canada addresses key concerns such as land contamination, air quality, waste disposal, water contamination, wildlife protection and abandonment and reclamation obligations. The *Canada Labour Code* is the primary Federal legislation governing occupational health and safety, while each province has also enacted specific occupational health and safety legislation.

In all jurisdictions, employers are required to take every reasonable precaution to protect the health and safety of their workers and persons attending project sites. Occupational health and safety legislation imposes health and safety obligations for both employers and employees in order to minimise the risk of workplace accidents. In some provinces, this obligation extends to the protection of the health and safety of all individuals at or near the employer's workplace, whether or not those individuals are employees.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Each of the Federal and provincial governments have enacted legislation to govern the abandonment and reclamation of lands subject to oil and natural gas development. The key components of abandonment and reclamation obligations under Federal and provincial legislation include: (i) the removal of equipment, buildings and other structures; (ii) the decontamination of such buildings, structures, land or water; (iii) stabilisation, contouring, maintenance and conditioning of affected lands; (iv) reconstruction and revegetation of the surface of the land; and (v) any other procedures or requirement that may be specified by the legislation in the applicable jurisdiction.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

There are various Federal and provincial statutes and regulations that govern the storage of natural gas in jurisdictions throughout Canada. The jurisdiction within which a storage facility is located is determinative of whether the facility is Federally or provincially administered. The majority of gas storage facilities in Canada are located in the provinces of Alberta and Ontario given the proximity of these jurisdictions to large upstream production (Alberta) and distribution points (Ontario).

In Alberta, the *Mines and Minerals Act* provides that the owner of the oil and natural gas rights also owns the storage rights with respect to the underground formations that form a part of the oil and natural gas rights. Storage rights under the *Mines and Minerals Act* provide the holder with the right to inject natural gas into a reservoir for the purpose of storage. In order to inject natural gas into a storage reservoir, a licence must first be obtained from the AER to drill an injection well, which licence is issued pursuant to the *Oil and Gas Conservation Act* (Alberta). In determining whether to issue a licence for the storage of natural gas, the AER takes into consideration conservation, equity, environmental, safety, capacity and deliverability issues.

In Ontario, the owner of the oil and natural gas rights also owns the storage rights with respect to underground formations. The *Oil, Gas and Salt Resources Act* (Ontario) governs the drilling of a well for the purpose of storage, and establishes the regulatory framework for the issuance of a licence from the Ontario Energy Board to drill a well for the purpose of injecting substances into underground formations. The Ontario Energy Board issues storage licences pursuant to the *Ontario Energy Board Act*, and has broad authority to designate gas storage areas to ensure the safe operation and development of gas storage facilities.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Natural gas imports and exports are regulated in Canada by the NEB. Section 116 of the NEB Act prohibits the export or import of any oil or natural gas, except in accordance with a licence issued under Part VI of the NEB Act or as may be authorised under the regulations. The NEB may issue an order authorising the importation or exportation of gas pursuant to section 15 of the *National Energy Board Act Part VI (Oil and Gas) Regulations* (Canada) ("**Part VI Regulations**").

Both an order and a licence for the exportation or importation of natural gas may be issued for periods of 2–20 years, in quantities of not more than 30,000 m^3 per day. For the exportation of natural gas for subsequent importation or the importation of natural gas for subsequent exportation, an order may be issued for a period of 2–25 years. However, further approval from the provincial regulatory body may be required in order to remove natural gas from the province.

While an order authorises the importation and exportation of natural gas, a licence may impose additional terms and conditions with respect to, among other things, the duration, quantity, tolerance levels, points of exportation or importation, and environmental requirements. A public hearing must be held by the NEB before a licence is granted.

LNG exportation requires a separate licence from the NEB. To date, these have generally been issued for terms of 20–25 years and include maximum annual quantities (subject to a 15% tolerance over any 12-month period) and maximum term quantities. However, in 2015 the maximum term for LNG export licences was extended from 25 years to 40 years, and some project proponents already in possession of issued export licences have since applied to have their licences extended for a 40-year term.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Oil imports and exports are regulated in Canada by the NEB and are governed by similar regulations to those of natural gas, subject to the differences highlighted herein.

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The NEB Act requires a licence for the exportation of oil for any period exceeding that granted by an order. The licence may impose terms and conditions similar to those in natural gas licences, as outlined in question 4.1. A public hearing must be held by the NEB before a licence is granted. Pursuant to section 24 of Part VI of the NEB Act's Regulations, the importation of oil is exempt from the licence and order requirements set out in the NEB Act, Part VI.

Pursuant to section 28 of Part VI of the NEB Act's Regulations, an order issued under the NEB Act for exportation of heavy crude oil may be issued for a period not exceeding two years. To export oil other than heavy crude the period cannot exceed one year. Such order may impose terms and conditions similar to a licence and, in addition, will include a requirement that a contract for the exportation of oil for a term exceeding one month must relieve the holder of the order of any obligation to export oil under the contract should exportations be restricted by the Government of Canada.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Each of the provincial and Federal governments of Canada has enacted legislation to oversee energy resource development throughout the country. The regulatory process that applies depends on the nature of the facilities and the applicable regulator.

The regulation of energy infrastructure primarily falls under the jurisdiction of the provinces, unless the work or undertaking is interprovincial or international in scope, in which case such work or undertaking falls under Federal jurisdiction. At the Federal level, transportation pipelines and associated infrastructure are primarily governed by the NEB. The NEB is also responsible for regulating tolls and tariffs of interprovincial or international pipelines. At the provincial level, transportation pipelines and associated infrastructure that are located wholly within a province, and not otherwise an integral part of a Federally regulated pipeline, are governed by the respective provincial or territorial regulator.

While the primary authorisations for interprovincial or international pipelines and associated infrastructure are under Federal jurisdiction and issued by the NEB, specific aspects of the pipeline or infrastructure project, such as construction, safety and environmental matters, may also be subject to provincial jurisdiction and oversight. At both the provincial and Federal levels of government, there are numerous statutes and agencies that oversee the construction, operation, safety and abandonment of oil and gas pipelines. There are also varying statutes and regulations governing oil and gas transportation and associated infrastructure involving First Nations lands, offshore areas, and the Canadian Arctic.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The construction and operation of interprovincial or international transportation pipelines are regulated by the NEB under the NEB Act. The process for approval depends on a number of factors, including the scope of the pipeline project. Major pipeline projects might undergo a written or oral hearing to consider issues of interest to various types of interveners, including landowners, Aboriginal communities, municipalities, provincial governments, and other stakeholders. The issues vary, but can include topics related to safety, the environment, technical considerations and stakeholder consultation outcomes. The NEB coordinates the input of other Federal and provincial agencies into the approval process and makes its decisions in the public interest.

Following a hearing, the NEB will issue a report to the Federal government detailing its recommendation regarding whether a major pipeline project should be approved, and, if so, the conditions the approval should be subject to, if any. After reviewing the report, the Federal government will direct the NEB to approve or deny the project. The NEB will issue successful project proponents a certificate of public convenience and necessity (a "**CPCN**") which will allow for the construction and operation of the pipeline. A CPCN is subject to whatever terms and conditions the NEB considers necessary or desirable in the public interest. An environmental assessment pursuant to the *Canadian Environmental Assessment Act, 2012* ("**CEAA 2012**") may also be required in connection with the NEB's approval of a pipeline project. Separate applications will also need to be made to the NEB to set tolls or terms and conditions of access and the export and import of oil and gas through the pipeline.

The authorisations required for the construction of an intraprovincial transportation pipeline vary depending on the province or territory and the governing provincial authority. Where required, the provincial regulators are responsible for conducting provincial environmental assessments related to energy resources activities. In some cases, the Federal and provincial environmental assessments may be combined into a joint environmental assessment or the province may agree to rely on the conclusions reached in a single Federal environmental process. In addition to approvals for the construction and operation of the proposed pipeline project, provincial regulations might also govern, among other things, environmental approvals, surface rights, compensation, and transportation rights. Federal regulatory approvals may also be required for provincially regulated pipelines, including in relation to dispositions of Federal Crown lands, First Nations land access, fisheries, navigable waters and species at risk.

The Federal government is currently undergoing a review process of CEAA 2012, the NEB Act and associated legislation, and is expected to announce legislative amendments and/or new legislation in December 2017.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

There are Federal and provincial processes that an entity may be required to follow in order to obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure, depending on the jurisdiction under which the pipeline project is regulated. Such processes include public consultation and notification requirements which may arise during the application process for the pipeline or associated infrastructure project. The process for obtaining access depends on whether the land is freehold (privately held) land, Federal or provincial Crown land.

For Federally regulated projects to be constructed on Federal Crown land, the project proponent will need to obtain a Crown land disposition or go through the appropriate regulator if there is an occupant on the land who refuses to grant access. On freehold lands, the proponent will need to come to an agreement with the landowner in order to obtain access. Land acquisition agreements may be entered into before project approval; however, the NEB Act outlines specific content that must be included in these agreements.

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If the proponent and the landowner cannot reach an agreement, the proponent may apply for a right of entry to the lands required for the project. Rights of entry are only available after the project receives approval, and may be granted by the NEB or relevant provincial regulator. The provincial regulator or a specialised federal tribunal will oversee and determine the compensation owed to the landowner by the proponent if compensation is not settled by agreement.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Oil pipelines are traditionally (but not always) common carrier pipelines. By statute, common carrier oil pipelines are required to accept and transport all oil tendered. There are allocation provisions in place to manage oversubscription of common carrier oil pipelines. In addition to common carrier pipelines, there are oil pipelines underpinned by long-term transportation contracts for all or a portion of the pipeline capacity as well as numerous provincial non-common carrier pipelines. At the Federal level, the NEB requires contract carrier pipelines to offer transportation contracts to all entities on the same terms and conditions (referred to as "open season") and to retain a portion of the pipeline capacity for uncontracted ("spot") shipments to fulfil the pipeline's common carrier obligations.

Natural gas pipelines are traditionally contract carriers. This means that pipeline space is allocated by private transportation contracts for all or a portion of the pipeline's capacity. While the terms of the transportation contracts are negotiated amongst the contracting parties, the NEB is responsible for ensuring "equal tolls for equal service" under the NEB Act for pipelines falling under Federal jurisdiction. Provincial regulators are responsible for regulating intraprovincial pipeline contracts and tolls under their respective enabling statutes.

Transportation contracts have varying terms and while pricing can be negotiated on an individual basis or based on the cost of service, it must meet the "just and reasonable" and "no unjust discrimination" standards set by the NEB. A transportation contract must pass the "economic feasibility" test, which means the investment will be recovered over the life of the pipeline through the payment of a demand charge. Pipeline companies are entitled to the opportunity to recover their cost of capital and the overall return on capital must meet the "fair return standard" set by the regulator.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Various gas transportation pipelines are integrated or interconnect at differing levels. Numerous federal pipeline systems are integrated with provincial pipeline systems located wholly within a province. These pipeline systems may be functionally integrated and subject to common management, control and direction. There may be a common ownership, purpose, and physical connection between the pipeline systems. In such cases, a pipeline that is otherwise located wholly within a province will be subject to federal regulation. Along with transportation pipelines being interconnected and integrated within Canada, there are various interconnections with the pipeline system in the United States of America. The different regulators and commissions throughout Canada and internationally, work with each other, as required, to assist in this integration and interconnection of pipeline systems.

A pipeline that is interprovincial or international (either because it crosses borders or is functionally integrated with a Federally regulated pipeline) falls under the jurisdiction of the NEB, is regulated in accordance with Federal pipeline standards and is subject to Federal application processes and conditions necessary for approval of the construction and operation of such pipeline system. If the operator of the existing pipeline refuses an interconnection with a new pipeline, the entity desiring the interconnection could apply for an NEB order to force the operator to accept the interconnection, subject to certain considerations such as whether the interconnection would impose an undue burden on the operator of the existing pipeline. Please see question 6.2 for further details on the required authorisations and application processes for constructing a transportation system.

An example of an integrated pipeline system within Canada is the pipeline system owned by NOVA Gas Transmission Ltd. This system, which is subject to Federal jurisdiction, runs through various provinces and is functionally integrated, under common ownership, as well as common management, control and direction.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

As noted in question 6.4, third-party access rights may depend on whether a pipeline has been designated a common carrier pipeline or a contract carrier pipeline. Depending on such designation, there are particular regulatory processes by which an operator can be required to expand its pipeline system.

In the case of a contract carrier pipeline, it is unlikely that a shipper or the applicable regulator would be able to force access to the pipeline and associated infrastructure, although there are mechanisms to do so in discrete cases. For example, in the Province of Alberta, a shipper could apply to the Alberta Energy Regulator (the "**AER**") to have a contract pipeline designated as a common carrier pipeline and force access to the pipeline and associated infrastructure. If expansion of a natural gas pipeline or storage facility is required, then the costs will either be borne *pro rata* by the shippers on the pipeline system or imposed more heavily on the shippers of the new volumes to be accommodated, as determined by the appropriate regulatory board having jurisdiction.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

If the pipeline falls under Federal jurisdiction, the NEB is responsible for determining the tolls and tariffs which apply to the transportation services provided by such pipeline and will continue to monitor these tolls and tariffs throughout the operation of the pipeline. The pipeline owner/operator must submit an application for approval of the tariff and the appropriate regulatory board will determine the tolls and tariffs to be offered to parties wishing to transport oil or natural gas on that particular pipeline. For smaller pipelines, the NEB operates on a complaint-based approach where disputes over set costs/tariffs are settled between the pipeline operator and the party using the service. Similar regimes exist for intraprovincial pipelines as determined by the provincial regulator.

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7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

As discussed in question 6.1, natural gas transmission pipelines in Canada are privately owned high-pressure lines that transport natural gas, primarily, from the gas-producing western provinces to the rest of the country and parts of the United States. As the natural gas transmission pipeline network predominately involves interprovincial pipelines, this sector is regulated by the NEB, which also approves transmission tariffs.

Natural gas is distributed to end-users through a network of low-pressure intraprovincial pipelines that fall under provincial jurisdiction. Provincial governments delegate their authority to oversee distribution pipelines to specialised utilities commissions. In addition, each province will generally have one or more private or government-owned utilities responsible for gas distribution, commonly called "local distribution companies" or "LDCs". It is the responsibility of each provincial utilities commission to oversee and approve the services, rates and operations of the LDCs. For the most part, LDCs are granted exclusive franchise rights to provide non-discriminatory distribution services in a particular area or municipality.

Most provinces have partially deregulated the retail natural gas market and have allowed both natural gas marketers and LDCs to sell gas to consumers, thereby "debundling" the sale and transport of natural gas. A consumer may choose to have an LDC supply natural gas at a regulated rate or contract with a gas marketer to purchase natural gas at a contracted rate.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

In general, an LDC requires a licence from the provincial regulator to construct and operate a distribution network, and the tariffs of the LDC must then be approved by the provincial utilities commission. An LDC may be able to obtain exclusive franchise rights to operate in an area, either under the operating licence or via a municipality franchise agreement.

7.3 How is access to the natural gas distribution network organised?

An LDC must provide distribution services to all end-users on or near their distribution network in a non-discriminatory fashion and in accordance with the tariffs sanctioned by the provincial utilities commission.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Provincial utilities commissions can typically order an LDC to provide distribution services to an end-user not currently connected to the distribution system. An order to connect and provide non-discriminatory access may be granted if such an order does not cause undue burden to the current ratepayers connected to the distribution system, as current ratepayers would be required to pay their *pro rata* share of costs incurred to facilitate such a connection.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

As general practice, a provincial utilities commission will set the rate as part of the tariff that an LDC may charge for providing distribution services. When setting a rate, the regulator will attempt to balance the interests of both end-users and the LDC; end-users must receive safe and reliable service at just and reasonable rates, but the rates must provide the LDC's shareholders with a fair return on their capital investment.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

In general, no change in control of the voting securities of an LDC or the transfer of any assets forming part of a distribution network may occur without regulatory approval from the provincial utilities commission (or commissions) with jurisdiction over the LDC or LDC assets at issue.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Since 1985, wholesale natural gas prices in both Canada and the United States have been deregulated in whole or in part, which has evolved over time into a sophisticated continental-wide wholesale energy market. The Canadian and American natural gas transmission network is connected by a vast and complex network of pipelines spanning across the countries' borders with multiple trading hubs. Contracts are traded in large quantities and prices are publicly available based on market forces in both countries. This system allows for seamless trading throughout the North American market.

Transaction prices are determined in the open market at or by reference to established wholesale market delivery/receipt points, which are discussed in further detail in question 1.1.

Natural gas can be traded on both a short-term and long-term basis, either physically or through the use of derivatives. Natural gas derivatives trading is regulated on a provincial level through province-specific securities or commodities legislation, and such legislation may impose certain registration and filing requirements.

Several provinces require natural gas marketers who sell natural gas to residential and small commercial consumers to be licensed. Furthermore, trading entities that are affiliates with a regulated utility, such as a transmission company, must follow certain rules to prevent preferential treatment. Finally, when trading and exporting natural gas across provincial or Federal borders, traders may require approval from either the NEB, outlined in question 4.1, or the applicable provincial regulator.

There are several initiatives under way that may affect natural gas trading. First, there is currently a proposal to create a Federal securities regulator in Canada, which would regulate commodities and derivative trading uniformly across the country. The G-20 has also been advocating its member countries to uniformly regulate derivatives. Second, the Canadian Securities Administrators

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("**CSA**") has proposed certain Business Conduct Rules in National Instrument 93-101, with the purpose of promoting responsible business conduct in "over the counter" derivatives markets.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas can be traded either on a short-term basis, via spot market trades, or using long-term bilateral contracts. In addition to physical gas trades, derivatives can be used to complete natural gas trades, most commonly as futures contracts or hedges, which can either be physically settled or financially settled. These derivatives can also be traded as: (i) off-exchange or "over the counter" derivatives; or (ii) on-exchange derivatives through trading platforms such as the NGX or NYMEX.

Due to deregulation, which is further discussed in question 7.1, the sale and trading of natural gas is no longer bundled with transmission and distribution services. Traders are able to separately purchase gas from one entity (be it a producer or another trader), and contract with another entity (for example, a transmission company), to secure transportation rights.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Federal and provincial governments do not impose ownership or organisational requirements on Canadian LNG projects, but rather leave such matters to be determined at the discretion of the project proponents. Nonetheless, the development of an LNG project is subject to numerous other regulatory requirements which will likely necessitate interaction with both Federal and provincial authorities. Depending on the circumstances, consultation and/or negotiations with local stakeholders may also be required, such as First Nations communities.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Various government approvals, licences and permits are required to construct and operate an LNG facility in Canada. Chief among these are environmental assessments and approvals prescribed by legislation. An important feature of both provincial and Federal environmental regimes is that where an environmental assessment is required, a clearly defined hierarchy of legislative authority is prescribed. Specifically, most (if not all) project-related permits issued by various Federal and provincial authorities cannot be granted until a ministerial decision on the environmental assessment of a project has been granted. That said, permit application activities, including regulatory consultation, can (in some cases) occur parallel to an environmental assessment.

Federal legislative regimes of general application relevant to the development and operation of an LNG facility include, but are not limited to, the *Fisheries Act* (Canada), the *Navigation Protection Act* (Canada), the *Species at Risk Act* (Canada), CEAA 2012, and the Technical Review Process of Marine Terminal Systems and Transhipment Sites process (commonly referred to as "**TERMPOL**"). Provincial legislative regimes of general application relevant to the development and operation of an LNG facility in British Columbia include, but are not limited to, the *Oil and Gas Activities Act* (British Columbia), the *Heritage Conservation Act* (British Columbia), the *Water Act* (British Columbia), and the *Wildlife Act* (British Columbia). Provincial legislative regimes specific to the LNG industry in British Columbia include the *Liquefied Natural Gas Facility Regulation* (British Columbia).

The *Constitution Act, 1982* (Canada) establishes a number of protections regarding the traditional rights of aboriginal or "First Nations" peoples. In the context of an LNG project, the most relevant of these is the duty of the Federal and provincial governments to consult with First Nations groups regarding a proposed project that could impact their rights and, where appropriate, accommodate their traditional rights and mitigate any infringement of such rights. Although this "duty to consult" technically burdens the government, in practice it is typically the proponents of a project that assume the management and cost of the consultation process, and this commonly occurs in close connection with the environmental approval processes.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

There is no direct regulation of the price or terms of services in the Canadian LNG sector.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

There are no third-party access rights in respect of LNG facilities imposed by regulation in Canada.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Since 1985, the Canadian petroleum market has been free from legislation that regulates, subsidises, or taxes oil. However, pursuant to the provision of the *Constitution Act, 1867* (Canada), the provinces have the authority to directly regulate retail fuel prices. For example, Prince Edward Island, Newfoundland and Labrador, Nova Scotia, New Brunswick and Quebec have enacted provincial legislation regulating retail fuel prices, which generally includes provisions designating maximum and minimum retail prices and margins.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Physical trading of oil is carried out by oil producers and oil trading merchants who buy, store, transport and sell oil. Crude oil futures and options are traded through standardised contracts on commodities exchanges, primarily NYMEX and the International Petroleum Exchange in London. The current benchmark for tracking over-the-counter trades of heavy crude in Canada is Western Canadian Select, priced for delivery at Hardisty, Alberta.

Federal and provincial governments do not have uniform legislation with respect to the treatment of derivatives (such as crude oil futures or options). Derivatives are regulated through securities regulatory authorities in all of the provinces as part of a newly implemented cooperative regulatory scheme.

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11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The *Competition Act*, (Canada) ("**Competition Act**") provides for the general regulation of trade and commerce in respect of anti-competitive practices in Canada. The Competition Act is administered and enforced by the Competition Bureau (the "**Bureau**"), an independent law enforcement agency headed by the Federally appointed Commissioner of Competition (the "**Commissioner**"). The Competition Act may be divided into two principal areas: criminal offences; and civilly reviewable conduct. The Bureau is responsible for investigating possible violations of the Competition Act. Where appropriate, the Commissioner may refer a matter under investigation to a separate body for a final determination. Criminal matters are referred to the Director of Public Prosecutions, who may initiate criminal proceedings before the courts. Civil matters are brought before the Competition Tribunal (the "**Tribunal**"), a specialised body comprised of Federally appointed justices and lay members.

While the Competition Act is administered Federally, certain provincial regulatory bodies in the energy sector have mandates that overlap with those of the Bureau. As an example, the Market Surveillance Administrator of Alberta (the "**MSA**") is responsible for monitoring and investigating the anti-competitive conduct of market participants in Alberta's electricity and retail natural gas markets. In 2014, the Bureau signed a memorandum of understanding with the MSA, which provides a framework for cooperative enforcement activities and information sharing. Other federal and provincial regulatory bodies in the oil and natural gas AER sector whose mandates may potentially overlap with the Burea include the AER, the Alberta Utilities Commission and the NEB. For example, conduct by an infrastructure owner in the oil and natural gas industry that may attract an investigation under the Competition Act may also lead to filing of a common carrier application with the AER.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The criteria for determining whether conduct is anti-competitive depends on the type of offence being alleged. The Competition Act covers a variety of behaviours that may restrict certain activities, including agreements among competitors, mergers, price maintenance, vertical restrictions and abuse of dominance. For example, Section 45 of the Competition Act targets agreements whose purpose is to restrict competition and prohibit certain agreements among competitors *per se*. Section 90.1 targets agreements that have the effect of restricting competition, even in the absence of an intention to do so.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The Bureau has the authority to initiate and conduct investigations into possible anti-competitive conduct. In the course of an investigation and with court authorisation, the Bureau's investigators may conduct interviews and oral examinations, search for and seize evidence, demand the production of documents and engage in wiretapping.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

The Tribunal has authority to make a variety of orders in relation to a merger. "Merger" is defined broadly in the Competition Act as follows:

> "…the acquisition or establishment, direct or indirect, by one or more persons, whether by purchase or lease of shares or assets, by amalgamation or by combination or otherwise, of control over or significant interest in the whole or a part of a business of a competitor, supplier, customer or other person."

The two main elements of this definition are "control" and "significant interest". While neither term is defined in the Competition Act, the Merger Enforcement Guidelines published by the Bureau suggest that a significant interest will be acquired when a party gains the ability to materially influence the economic behaviour of the target business.

Although all transactions are subject to the Competition Act, only those that meet prescribed thresholds regarding party size, transaction size and shares/economic interest acquired are subject to notification requirements. If these thresholds are met, the parties to the transaction are required to notify the Commissioner and provide certain information in respect of the transaction. Unless the Commissioner requests supplementary information, the parties may close the transaction 30 days after providing notification. The parties may also request an advance ruling certificate (an "**ARC**"). The Commissioner will issue an ARC where he is satisfied that there are not sufficient grounds upon which to challenge the merger before the Tribunal. If the Commissioner does not believe that sufficient grounds exist to challenge the transaction, but is not willing to issue an ARC, he may issue a "no-action letter". While a no-action letter is highly indicative of the Commissioner's intentions, and a substantial number of transactions close on this basis, the Commissioner retains the right to challenge the transaction for one year following closing.

If a transaction is challenged, the Tribunal will determine whether the merger prevents or lessens, or is likely to prevent or lessen, competition substantially in a market. The Competition Act provides a non-exhaustive list of factors for the Tribunal to consider in this analysis, such as the likelihood that the transaction would result in the removal of an effective competitor and the extent to which foreign products/competitors are likely to provide effective competition. A transaction that is found to prevent or lessen competition substantially may still be allowed to proceed based on the efficiencies defence prescribed by the Competition Act – the Tribunal will not make an order if it finds that the merger has or is likely to bring about gains in efficiency that will be greater than, and will offset, the anti-competitive effects resulting from the transaction.

In the event that a completed transaction fails the above noted test and also cannot rely on the efficiencies defence, the Tribunal may order the dissolution of the transaction, the disposition of assets or shares, and/or other appropriate action. In the case of a proposed transaction, the Tribunal may order the parties not to proceed with the entire transaction or any part thereof, and/or other appropriate action. The Supreme Court of Canada has confirmed that a remedy need not restore competition to the way it was before the transaction, but simply to a state that would avoid substantial lessening of competition contrary to the Competition Act.

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Certain mergers in the oil and natural gas sector that trigger a Competition Act filing may also require clearance under the Canada Transportation Act (the "**CTA**"). Section 53.1 of the CTA states that parties required to notify a proposed acquisition under the Competition Act must also give notice of the same to the Minister of Transport if the acquisition "involves a transportation undertaking". The Minister of Transport then has 42 days to review the transaction and determine whether it raises issues with respect to the public interest as it relates to national transportation. While "transportation undertaking" is not defined, where a party to a notifiable transaction under the Competition Act is involved in a business that transports products (including energy products such as oil, natural gas and electricity) across Canadian provincial borders, approvals of the Minister of Transport may be required.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

Acquisitions of oil and gas interests in Canada by foreign companies will be subject to the general application of the *Investment Canada Act* ("**ICA**"). For certain investors, the ICA provides that governmental review will be triggered where a foreign investor is directly acquiring control of a Canadian business where the book value of the assets of the business (where assets are being acquired) or of the entity that owns the business (where an entity is being acquired) exceeds CAD $1 billion, which will be adjusted annually at the beginning of 2019. This threshold applies to acquisitions by: (i) WTO investors that are not state-owned enterprises; and (ii) non-WTO investors that are not state-owned enterprises where the Canadian business being acquired is, immediately prior to the acquisition, "controlled by a WTO investor".

Higher thresholds apply to acquisitions being made by: (i) trade agreement investors that are not state-owned enterprises; or (ii) non-trade agreement investors that are not state-owned enterprises where the Canadian business that is the subject of the investment is, immediately prior to the implementation of the investment, "controlled by a trade agreement investor". The review threshold for these acquisitions is CAD $1.5 billion, which will be adjusted annually beginning in 2019. Trade agreement investors include entities and individuals whose country of ultimate control is party to one of the following trade agreements: Canada-European Union Comprehensive Economic and Trade Agreement Implementation Act; North American Free Trade Agreement; Canada-Chile Free Trade Agreement Implementation Act; Canada-Peru Free Trade Agreement Implementation Act; Canada-Columbia Free Trade Agreement Implementation Act; Canada-Panama Economic Growth and Prosperity Act; Canada-Honduras Economic Growth and Prosperity Act; or Canada-Korea Economic Growth and Prosperity Act.

Where the acquisition is being made by: (i) WTO investors that are state-owned enterprises; or (ii) non-WTO investors that are state-owned enterprises, where the Canadian business being acquired is, immediately prior to the implementation of the investment, "controlled by a WTO investor", the review threshold for 2017 is CAD $379 million, and will be adjusted annually depending on growth in nominal GDP.

Lower thresholds apply to acquisitions by an investor who is not a "WTO investor" which involve the acquisition of control of a Canadian business which is not "controlled by a WTO investor" immediately prior to the implementation of the investment. These thresholds are CAD $5 million in asset value for direct investments, and for indirect investment, either CAD $5 million or CAD $50 million in asset value depending on the proportion of Canadian assets.

Where a proposed acquisition triggers an ICA review, the foreign investor cannot complete the transaction without ministerial approval. In deciding whether to approve an acquisition, the Minister will consider whether the investment is likely to be of "net benefit" to Canada. In making this determination, the Minister will take into account any undertakings provided by the foreign investor to the Canadian government in connection with the proposed acquisition. In practice, undertakings are required for almost any review under the ICA. In addition, the ICA also allows the Minister to review a transaction to determine whether it could be injurious to national security, and to accept undertakings related to any such concerns. With respect to Canada's oil sands industry in particular, the acquisition by CNOOC of Nexen in early 2013 led to a shift in government policy, such that an acquisition of control of a Canadian oil sands business by a foreign state-owned enterprise would be considered a "net benefit to Canada on an exceptional basis only". In October 2015, Canada elected a new Liberal government, which is widely seen as being more open to investment from foreign state-owned enterprises, including investments in Canadian oil sands businesses.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The main international treaties of general application to investment in Canada's oil and gas industry are Canada's various bilateral and multilateral free trade agreements ("**FTAs**") and bilateral foreign investment protection and promotion agreements ("**FIPAs**") (more commonly referred to internationally as "BITs" or "bilateral investment treaties"). Canada currently has 14 FTAs in force, a number of which include investment protection chapters similar in scope and substance to Canada's FIPAs. FTAs recently ratified by Canada include the Canada-European Union Comprehensive Economic and Trade Agreement ("**CETA**") and the Canada-Ukraine FTA. Canada is currently in the process of negotiating the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**") which is an FTA with the remaining members of what was the Trans-Pacific Partnership, an FTA which was signed in February 2016 but never came into force. Both the CPTPP and CETA include investment protection chapters. Canada currently has 37 FIPAs in force and six FIPAs concluded but awaiting ratification.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Generally speaking, Canada does not impose any compulsory

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dispute resolution procedures (statutory or otherwise) on its oil and gas sector, with the notable exception of disputes related to tariffs on regulated oil and gas pipelines, which must be heard by specially mandated administrative bodies. Other specialised governmental dispute resolution forums include the Alberta Surface Rights Board, which is charged, for example, with overseeing access disputes among oil and gas operators and local landowners in Alberta.

Participants in Canada's oil and gas industry will typically expressly attorn to the courts of the province with the closest connection to the parties or the subject transaction, services or operation, or agree to binding arbitration, including under various available provincial arbitration acts and arbitral rules/institutions. Generally speaking, there are also no bars to private enterprises bringing a claim against governmental regulators in local courts where such a claim is warranted (see also questions 13.3 and 13.4 below).

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Foreign arbitral awards are enforceable in Canada under legislation implementing both the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the UNCITRAL Model Law on International Commercial Arbitration. Canada's Federal government and each province other than Ontario have implemented both the New York Convention and the UNCITRAL Model Law. Ontario has only adopted the UNCITRAL Model Law.

Canada ratified the ICSID Convention on the Settlement of Investment Disputes between States and Nationals of Other States in 2013. Also, when ratifying the ICSID Convention, Canada designated British Columbia, Alberta and Ontario as constituent subdivisions capable of consenting to ISCID arbitration in their own right, with the result that foreign investors are able to enter into ICSID arbitration clauses directly with these provincial governments.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

As natural gas and oil production and transmission facilities in Canada are not typically owned by the Federal or provincial governments, this question has limited application in Canada. Furthermore, all Canadian provinces and the Federal government have passed legislation which leaves the government liable in tort. However, the Federal and provincial statutes often carry several specific notice requirements in which notice of the claim must be given to the government within a certain number of days after which the claim arose.

The liability exposure of municipal governments must be examined separately in light of applicable provincial statutes which may limit the liability of municipal corporations or hold plaintiffs to unique and strict limitation and notice periods.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

Foreign corporations have successfully obtained judgments against the Government of Canada in multiple occasions under NAFTA, with awards reaching up to CAD $130 million. While there has yet to be a successful judgment awarded in favour of an oil and gas entity, Lone Pine Resources Inc. is currently suing Canada for USD $118.9 million under Article 11 of NAFTA over Quebec's moratorium on natural gas fracking. The hearing took place in October 2017 but as of the date of publication, the decision has not been released.

Additionally, both Murphy Oil Corporation and Mobil Investments Inc. are currently suing the Federal government in connection with interests in two offshore petroleum developments and the legality of the Guidelines for Research and Development Expenditures promulgated by the Canada-Newfoundland Offshore Petroleum Board.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

On November 2016, the Federal government announced a $1.5 billion Ocean Protection Plan ("**OPP**") to improve marine life health and safety in response to tanker and fuel spills that have occurred in Canadian coastal waters, which included a five-year spend commitment commencing in 2017. The purpose of the OPP is to create a marine safety system, restore ocean ecosystems, develop new methods to clean up spills and establish new legislation to hold owners responsible for the operation of their vessels. To date, over $450 million has been invested as a part of the OPP.

In furtherance of the OPP, on May 12, 2017, the Federal government introduced legislation to formalise the Oil Tanker Moratorium Act on British Columbia's north coast. Once passed by Parliament, the new legislation will prohibit tankers from carrying more than 12,500 metric tonnes of crude oil or persistent oil products as cargo from stopping, loading or unloading at ports and marine installations in northern British Columbia.

In addition, a recent Federal Court of Appeal decision found certain Federal Regulations, requiring all diesel fuel produced, imported or sold in Canada to contain at least 2% renewable fuel, to be constitutional. This decision is significant because it enables the Federal government to enact legislation aimed at reducing greenhouse gases and the power to further its climate change initiatives, such as OPP, through legislation that may impact the oil and natural gas sector.

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Christine has significant experience advising clients with general corporate and commercial matters, all aspects of conventional and unconventional oil and gas matters, including liquefied natural gas, pipeline and other midstream project matters, including storage and crude by rail terminals, share and asset purchase and sale transactions and due diligence matters.

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Croatia

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In 2015, gross inland consumption (production + imports – exports + storage variations) of natural gas in Croatia amounted to 2.08 Mtoe, whereas about 1.47 Mtoe thereof was covered by domestic production of natural gas [www.ec.europa.eu/energy, Statistical Pocketbook 2017, page 196]. At the moment, Croatia is not completely dependent on the import of natural gas because about 56.1 per cent of natural gas supplied in 2015 was covered by domestic production from fields in the Pannonian basin and from offshore fields in the North Adriatic. The remaining demand was covered by imports of natural gas. [Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, page 133, available at http://www.mzoip.hr/doc/energija_u_hrvatskoj_za_2015_godinu.pdf.] In 2016, the entry of gas into the transmission system reached 27.689 kWh, out of which 10.855 kWh (39.2 per cent) originated from domestic production, 12.836 kWh (46.4 per cent) from imports and 3.998 kWh (14.4 per cent) from the underground gas storage facility PSP Okoli (UGS Okoli). [Annual Report 2016 of the Croatian Energy Regulatory Agency, page 135, available at www.hera.hr.] Due to the continuous decrease in domestic production, Croatia's dependence on gas imports is expected to grow significantly in the future.

In the Croatian gas and oil industry, the key market player is INA-INDUSTRIJA NAFTE d.d. (INA), a vertically integrated company 49.08 per cent owned by MOL Hungarian Oil and Gas Plc., 44.84 per cent owned by the Republic of Croatia and 6.08 per cent owned by institutional and private investors [www.ina.hr]. As regards the ongoing INA-MOL dispute, please see question 13.2 below. At the moment, INA is the only producer of natural gas in Croatia.

Although the Croatian gas market has legally been liberalised since 1 August 2008, the first signs of *de facto* opening of the market have occurred in the gas season 2012/2013 following the removal of a price cap for gas supply to eligible customers (but only in relation to non-household customers), and new wholesale suppliers entering the market. Under the old legal regime, all public suppliers purchased gas at prices regulated by the Croatian Government from PRIRODNI PLIN d.o.o. (PRIRODNI PLIN) (owned by INA). In light of this, INA (through its affiliated company PRIRODNI PLIN) in its capacity as the major wholesale natural gas supplier, and also an importer of natural gas, continued to dominate the gas supply market with a market share of nearly 68 per cent until 31 March 2014. In 2015, INA market share dropped down to 22.7 per cent, and two new important players in their field of gas supply are HEP Group companies with a market share of 43.2 per cent and PRVO PLINARSKO DRUŠTVO d.o.o. (PPD) with a market share of 22.7 per cent.

The reason for this is that, following the amendments to the Croatian Gas Market Act (ZTP) [*Zakon o tržištu plina*, Official Gazette nos. 28/13, 14/14 and 16/17], on 1 April 2014, the State-owned electricity company Hrvatska elektroprivreda d.d. (HEP) has been appointed the new supplier on the wholesale market in Croatia, taking over the similar role of 'supplier of public suppliers' from a procurement entity PRIRODNI PLIN. This means that HEP (through its affiliated company HEP-Opskrba plinom d.o.o.) was the key wholesale gas supplier to other Croatian suppliers with PSOs for the needs of household customers until 31 March 2017. INA, as the only Croatian producer of natural gas, was under an obligation to sell a set volume of gas to HEP at a regulated price. During this three-year transitional period, the price at which gas produced in Croatia is sold to HEP, and the price at which HEP then sells it to other PSO suppliers has remained regulated. In addition, HEP has been awarded 70 per cent priority for booking storage capacity with the UGS Okoli.

Consequently, at the end of May 2015, the European Commission launched a formal infringement procedure against Croatia. The European Commission's view is that the national gas market rules introduced in 2014 create unjustified barriers to the export of domestic gas production and restrict gas imports from other Member States. Moreover, the existing price regulation for non-household customers and the regime on access to, and capacity allocation of, storage are considered not fully compatible with EU internal energy market rules [Commission's reasoned opinion sent to Croatia on 26 February 2016, available at http://europa.eu/rapid/press-release_MEMO-16-319_EN.htm].

On 17 February 2017, the Croatian Parliament enacted the eagerly awaited amendments to the Gas Market Act that are primarily intended to remove the current gas import and export restrictions and to allow further opening of the Croatian gas market. The Act on Amendments to the Gas Market Act [*Zakon o izmjenama i dopunama Zakona o tržištu plina*, Official Gazette no. 16/17] entered into force on 23 February 2017 and became fully applicable as of 1 April 2017.

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The following overview provides a summary of the key amendments to the Gas Market Act:

- The regime of appointing a wholesale gas supplier to other Croatian suppliers with PSOs has been kept. However, prior to appointing a supplier in the wholesale gas market, a tender has to be conducted by the Ministry of Environment and Energy (*Ministarstvo zaštite okoliša i energetike*; MZOE) in cooperation with the Croatian Energy Regulatory Agency (*Hrvatska energetska regulatorna agencija*; HERA) and the Croatian Energy Market Operator (*Hrvatski operater tržišta energije d.o.o.*; HROTE). Additionally, an important prerequisite for the tendering process to take place in practice is that HERA conducts a prior investigation into the functioning of the gas market. It follows that the launching of the tender will depend upon a market report of HERA based on its view on the (effective) functioning of the Croatian gas market. The new rules do not foresee any time limits for the submission of HERA's report to MZOE. Following the tendering procedure, the Government should appoint a preferred supplier in the wholesale gas market for a definite period of time, which would be obliged by law to supply gas under regulated conditions to other suppliers with PSOs for the needs of household customers and to ensure a reliable and secure gas supply. Until then, HEP (through its affiliated company HEP-Opskrba plinom d.o.o.) remains the key wholesale market supplier to other public service suppliers for the needs of household customers.
- The Croatian Government should, subject to prior approval from HERA, determine a "strategic share" of gas storage booking capacity to be allocated to the appointed wholesale market supplier for a period of five (5) years in order to ensure a reliable and secure gas supply to household customers. However, in the interim period (that is as of 1 April 2017 until the above-mentioned decision is taken by the Government), the existing wholesale market supplier (HEP) has been awarded 60 per cent priority for booking storage capacity with the UGS Okoli. Nevertheless, the Government has been given the possibility, upon the proposal of MZOE and subject to prior approval by HERA, of reassigning the allocated storage capacity to a supplier with a PSO that decides to procure gas under market conditions for its customers entitled to such supply.
- For the time being, a system of regulated retail prices for household customers remains in place. On 28 February 2017, the Croatian Government adopted a decision on the gas price at which the wholesale market supplier (HEP) sells gas to other suppliers with PSOs for the needs of household customers and for heat generation with effect from 1 April 2017 until 31 March 2018. As a result of this decision, since the Government was under strong pressure to prevent price increases for households due to recent legal changes, the final gas price for household customers as of 1 April 2017 until 31 March 2018 will remain at about the same level as compared with the same period last year.
- The obligation imposed on gas suppliers with PSOs and the supplier of last resort, pursuant to which they are obliged to primarily purchase gas from a domestic gas producer, and to purchase any remaining gas quantities from a trader and any other supplier on an organised gas market or from gas imports, has been abolished.
- Suppliers with PSOs are entitled, but no longer required by law, to buy gas from the appointed wholesale market supplier (HEP). The current obligation imposed on gas suppliers with PSOs and the supplier of last resort to purchase the gas for the needs of household customers from the appointed wholesale market supplier (HEP), has been abolished.
- The domestic producer of natural gas is now allowed to sell gas at market prices. The current obligation imposed on the domestic gas producer (INA) to sell its total gas volumes at a regulated price primarily to the wholesale market supplier and the supplier of last resort, and to sell any remaining gas quantities in Croatia, has been abolished.

Gas transmission, distribution and storage of natural gas are regulated energy activities performed as a public service. The ZTP provides for a new unbundling regime with the following three models: (i) the ownership unbundling model; (ii) the independent system operator (ISO); and (iii) the independent transmission operator (ITO). However, the legal unbundling process of the activities related to the gas transmission and gas storage has already been carried out.

Domestic transmission lines are owned and operated by the 100 per cent State-owned company PLINACRO d.o.o., which was separated from INA in 2002. In 2007, PLINACRO was designated as the transmission system operator (TSO) for a period of 30 years. In line with the ZTP, PLINACRO still remains to be certified as an ownership unbundled TSO. The gas production fields of the Pannonia and North Adriatic, the UGS Okoli, 35 distribution systems and 21 final customers are connected to the transmission system. [Annual Report 2016 of the Croatian Energy Regulatory Agency, page 120, available at www.hera.hr.] The Croatian gas transmission system is 2,694 km long and has been continuously expanded in recent years [www.plinacro.hr]. Under the previous PLINACRO's Plan for the Development, Construction and Modernization of the Gas Transmission system of the Republic of Croatia in the period 2002–2011, the regional gas pipeline network Lika – Dalmacija from Bosiljevo to Split was completed in May 2013. Although PLINACRO's expanded gas pipeline network covers now around 95 per cent of the Croatian territory, the distribution system and the gas consumption do not follow the development of the transmission system. In December 2017, a new PLINACRO's Ten-Year Development Plan of the Croatian Gas Transmission System in the period 2018–2027 [Ten-Year Plan, *Desetogodišnji plan razvoja plinskog transportnog sustava Republike Hrvatske 2018.-2027.*, available at http://www.plinacro.hr/UserDocsImages/dokumenti/Desetogodi%C5%A1nji%20plan%20razvoja%20PTS%202018-2027.pdf] was approved by HERA. The current gas supply forecasts indicate the need for further transmission capacity and significant investment in the construction of new parts of the gas transmission system with regard to its integration into new strategic supply projects. Therefore, the two most important projects under the Ten-Year Plan are the planned construction of the LNG terminal on the Island of Krk in the North Adriatic and the Ionian-Adriatic Pipeline (IAP). The IAP project intends to connect the Croatian and Albanian pipeline system with the Trans Adriatic Pipeline (TAP) [TAP is part of the EU-designated Southern Gas Corridor with a length of 800 km, running from Greece to Italy, via Albania and the Adriatic Sea]. The total gas pipeline length from Croatia (Ploče) to Albania (Fieri) is 540 km and has an annual pipeline capacity of 5 billion m^3/year. This is a strategically important project, whose implementation will enable the creation of a new energy corridor for the region of South-East Europe, with the aim of establishing a new supply of natural gas from new sources – the Caspian and Middle Eastern regions. The IAP project has been included in the list of EU Projects of Common Interest (PCI).

Currently, two cross-border interconnections in Croatia exist, being (i) interconnection Dravaszerdahely–Donji Miholjac (Hungary–Croatia), and (ii) interconnection UMS Rogatec (Slovenia–Croatia). Please note that gas can only be imported from Slovenia and Hungary to Croatia. In this context, the Ten-Year Plan also addresses the problem of the security of supply, N-1 criterion and bidirectional flow at the interconnections. Therefore, and to avoid possible physical congestions in the gas pipeline network, the centrepiece of the Ten-Year Plan are projects for the construction of compressor stations

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and new interconnection in the direction of Lučko–Zabok–Rogatec (Slovenia). [PLINACRO's Ten-Year Plan, page 53–56.] In addition, the Ten-Year Plan anticipates projects for connecting the Croatian gas transmission system to the gas transmission systems of other neighbouring countries (e.g. Bosnia and Herzegovina, Serbia and Montenegro). A number of new planned projects have been included in the EU PCI and Projects of Energy Community Interest list (PECI).

In 2016, there have been 35 active gas distribution operators in Croatia, among which the two most important are GRADSKA PLINARA ZAGREB d.o.o. and HEP-PLIN d.o.o. The total length of the gas distribution network in Croatia at the end of 2016 was 19,153 km.

The only underground natural gas storage facility in Croatia is PSP Okoli (UGS Okoli) located near the city of Sisak with a total gas storage capacity of 553 million m³. The gas storage operator is PODZEMNO SKLADIŠTE PLINA d.o.o. (PSP) [www.psp.hr]. This company was legally unbundled from INA and bought by the State-owned PLINACRO in 2009. The gas storage operator PSP continues to expand the UGS Okoli to increase gas storage capacity, as well as to decrease negative environmental impact. Moreover, the main investment over the mid-term concerns the planned construction of a small underground gas storage facility in Grubišno Polje.

Currently, no LNG facility exists in Croatia. Perhaps one of the most important projects in the gas sector concerns the planned construction of the floating LNG terminal on the Island of Krk in the North Adriatic with a capacity of 2 billion m³/year (LNG Terminal). This would open a cross European North-South corridor and improve the natural gas supply security of the region. The planned LNG re-gasification facility has been given PCI status. On 29 October 2014, the project has been included in the indicative list of key energy infrastructure eligible for financial support under the Connecting Europe Facility (CEF) Energy 2014 programme. Under the Decision dated 16 July 2015 of the Croatian Government, the LNG Terminal project has been also designated as a project of strategic importance to the Croatian State (PSI). In June 2016, the Croatian Government adopted a decision to speed up the preparation and implementation of the first phase of the LNG project that involves construction of the floating storage and regasification unit (FSRU). At the same time, LNG Hrvatska d.o.o. (LNG Croatia) [www.lng.hr] (with HEP and PLINACRO each holding 50 per cent of the equity shares thereof) was given the status of the project developer. From March 2017, preparation of project and permitting documentation and activities related to procurement of FSRU are under way for the construction of the floating LNG terminal [http://www.lng.hr/en/news-details/floating-lng-terminal-implementation-kick-off-68]. The Financing Agreement for the construction of the first phase of the LNG project under the CEF was signed at the Energy Council of 18 December 2017 [https://ec.europa.eu/inea/en/connecting-europe-facility/cef-energy/projects-by-country/croatia/6.5.1-0018-hr-w-m-16]. According to current plans, all construction work on jetty, pipeline and auxiliary facilities should be completed by the end of 2019, and the release of the first gas from the terminal to the system is expected in early 2020 [http://www.lng.hr/en/news-details/goran-francic-managing-director-of-lng-croatia-visited-dnevnik-3-80]. The Final Open Season phase for customers who could book the capacity of the LNG terminal on a long-term period is expected to be launched by mid-January 2018 [http://www.lng.hr/en/open-season].

As regards projects allowing gas to flow from Croatian LNG terminal to neighbouring countries, the phased development of the LNG terminal and gas pipeline Zlobin–Bosiljevo–Sisak–Kozarac–Slobodnica has been included in the updated EU PCI list as of 18 November 2015 [https://ec.europa.eu/energy/sites/ener/files/documents/5_2%20PCI%20annex.pdf.]

Croatia has introduced the entry-exit model and a virtual trading point (VTP) as of 1 January 2014.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Croatia's primary energy supply is dominated by liquid fuels [Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, page 47]:

- Liquid fuels – 32.8 per cent.
- Coal and coke – 7.5 per cent.
- Natural gas – 21.9 per cent.
- Electricity – 6.1 per cent.
- Hydro Power – 15.5 per cent.
- Heat – 0.2 per cent.
- Fuel wood – 13.3 per cent.
- Renewables – 2.9 per cent.

The above data shows that the share of natural gas in the consumption of Croatia's primary energy (21.9 per cent) is exceptionally significant. Croatia is still covering larger part of its needs by domestic production (40–45 per cent), primarily because the consumption of gas has significantly decreased over the last few years. However, future supply forecasts, and the expected moderate increase of consumption, indicate that imports of larger gas volumes will be required. [PLINACRO's Ten-Year Plan, page 6.]

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Domestic natural gas production is performed by INA. INA reported their reserves at the end of 2016 at 98 million boe of natural gas. About 56.1 per cent of total domestic demand in 2015 was covered by domestic production from 16 onshore fields in the Pannonian basin and 10 offshore fields in the North Adriatic (see question 1.1 above). [Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, page 133.] In 2015, the total domestic production of natural gas was 1,850.5 million m³.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Data of the Energy Balances of Natural Gas for 2015 shows that the total export of natural gas in 2015 was 367.4 million m³ [Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, page 140]. LNG is not exported from Croatia.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

The exploration, production and refining of crude oil, and most of the trade in oil derivatives and LPG is carried out by INA Group companies. Crude oil is produced at 33 oil fields, and gas condensates at eight gas condensation fields. [Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, page 107.]

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INA operates two oil refineries and one lubricant products plant. Processing of oil and production of oil products is carried out in the Oil Refinery Rijeka located in Rijeka (Urinj), next to the Adriatic Sea with a total of 4.5 million tonnes of annual crude oil processing capacity or 90,000 bbl/day, and in the Oil Refinery Sisak, close to the domestic oil fields and in the centre of Croatian market, with a total of 2.2 million tonnes annual crude oil processing capacity or 44,000 bbl/day. In addition, INA operates the Lube Refinery Zagreb, where lubricants are produced. [Available at www.ina.hr; Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, page 107.] In the last few years, INA carried out the project of the refinery modernisation in Rijeka and Sisak in order to comply with EU requirements and standards.

Transportation of oil through oil pipelines in Croatia is performed by Jadranski naftovod d.d. (JANAF). [Ownership structure of JANAF: 37.26 per cent owned by the State Office for State-owned Property Management/Croatian Pension Fund; 26.28 per cent owned by the Croatian Restructuring and Sale Centre; 11.80 per cent owned by INA; 10.6 per cent State-owned; 5.36 per cent owned by HEP; 4.30 per cent owned by the State Office for State-owned Property Management/State Agency for Deposit Insurance and Bank Rehabilitation; and 4.34 per cent owned by institutional and private investors.] The JANAF oil pipeline was completed in 1979 as an international crude oil transportation system with a designed capacity of 34 million tonnes/year and an installed capacity of 20 million tonnes/year. The crude oil quantities transported through the JANAF oil pipeline in 2016 amounted to 7.1 million tonnes. The JANAF oil pipeline system has a longitude of around 622 km with the following sections: Omišalj – Sisak, Sisak–Virje (with a section to Lendava in Slovenia) – Gola (Croatian-Hungarian border); and Sisak–Slavonski Brod (with a section to Bosanski Brod in Bosnia and Herzegovina) – Sotin (Croatian-Serbian border). Crude oil is imported by tankers through the sea terminal in Omišalj on the Island of Krk in the North Adriatic. However, the oil pipeline system can also be used to import oil by land. The biggest crude oil handling terminal located in Omišalj has a storage capacity of 1 million m^3 for oil and 60,000 m^3 for oil products. Other crude oil handling terminals are located in Sisak and Virje, with a storage capacity of 500,000 m^3 in Sisak and 40,000 m^3 in Virje. The submarine oil pipeline Omišalj – Urinj has a longitude of 7.2 km, with a submarine section of around 6 km, and connects the Omišalj Terminal with the INA's Oil Refinery in Rijeka. Oil derivatives terminal JANAF-Žitnjak is located in Zagreb with a storage capacity of 142,000 m^3. The total storage capacity of the JANAF system amounts to 1.54 million m^3 for oil and 202,000 m^3 for oil products. [Available at www.janaf.hr; Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, pages 108.] According to HERA's licence registry, a total of 21 companies are licensed as oil and oil products storage operators. Croatia has three ports which can receive oil and oil products: Omišalj; Zadar; and Ploče.

The JANAF-Adria pipelines project has been given PCI status and included in the updated EU PCI list as of 18 November 2015. The project involves the reconstruction, upgrade, maintenance and increase in capacity of the existing JANAF and Adria pipelines linking the Croatian Omišalj seaport, through Hungary, to the Southern Druzhba pipeline in Slovakia.

The first LPG terminal in Croatia which is located some 35 km from Zagreb (Sv. Križ Začretje) was completed in 2009. The LPG terminal with 13 storage tanks (each 5,700 m^3) is owned and operated by the company CRODUX PLIN d.o.o.

Currently, the construction of two new LPG and oil derivatives handling terminals with the total storage capacity of 273,000 m^3 in the port area of Luka Ploče in the South Adriatic is under way. The terminal is being developed as the Adriatic Tank Terminal (ATT). In December 2014, the company PPD (now part of Energia Naturalis (ENNA) group) has signed a sub-concession contract to construct and operate the LPG and oil derivatives terminals. PPD has also signed a memorandum of understanding for development of these two terminals with the company VTTI, a provider of energy storage worldwide (co-owned by Vitol, one of the largest energy traders in the world, and MISC, a leading international shipping and maritime conglomerate). In September 2016, the first stage of ATT has been completed with the construction of 50,000 m^3 of capacity terminal for white petroleum products. Reportedly, the second stage of construction will ensure a capacity of more than 200,000 m^3 for petroleum, as well as 60,000 m^3 for the storage of LPG [http://www.enna.hr/en/the-port-of-ploce-t3]. This would open a new supply route for the LPG by sea.

The Croatian Mandatory Oil Stocks Agency (*Hrvatska agencija za obvezne zalihe nafte i naftnih derivata*; HANDA), which has been merged with the Croatian Hydrocarbon Agency (*Agencija za ugljikovodike*; AZU) in September 2017, is the entity responsible for the maintenance of the mandatory stocks of crude oil and oil products of the Republic of Croatia; it is also responsible for establishing the mandatory stocks in the quantity of the 90-day average daily consumption in the previous calendar year by 31 July of the current year.

The total number of fuel stations was some 826 in 2015, out of which some 382 petrol stations were owned by INA. [Annual Energy Report for 2015 of the Croatian Ministry of Environment and Energy, Energy in Croatia 2015, page 109.] According to HERA's licence registry, there are currently a total of 47 oil products wholesalers in Croatia (e.g. INA, PETROL d.o.o., CRODUX DERIVATI DVA d.o.o., etc.), only one LPG wholesaler and retailer (INA), 11 LPG wholesalers and one company licensed for the road transport of crude oil, oil products and biofuels.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Consumption of liquid fuels represents the main energy source in Croatia. It is expected that in the long run, fossil fuel production will gradually decrease in favour of renewable energy sources. Nevertheless, it is expected that the share of liquid fuels in energy consumption in Croatia will continue to be very high in the upcoming period (see also question 1.2 above).

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

The production of domestic oil products is carried out by INA. Only about 19 per cent of domestic requirements for crude oil may be covered by domestic production of oil and condensates. The total production of crude oil in 2016 amounted to 684,000 tonnes of oil [Annual Report 2016 of the Croatian Energy Regulatory Agency, page 161]. Croatia, thus, is dependent on the import of oil. INA reported their proven reserves at the end of 2016 as 86 million bbl of oil. Crude oil production in 2016 amounted to 15.0 million boe/day and condensate production to 1.9 million boe/day [https://www.ina.hr].

2.4 To what extent is your jurisdiction's oil production exported?

Croatia does not export crude oil; it exports oil products. In 2016, about 79 per cent of the imported crude oil, 19 per cent of the

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domestic crude oil and 2 per cent of the domestic condensates were used as raw material for oil products production. [Annual Report 2016 of the Croatian Energy Regulatory Agency, page 162.] The total production of oil products in 2016 amounted to 3.4 million tonnes of oil products. Nevertheless, the significant share of the oil products in the Croatian market originates from imports.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Exploration and production of oil and natural gas reserves in Croatia is primarily regulated by the new Hydrocarbons Exploration and Production Act (ZIEU) [*Zakon o istraživanju i eksploataciji*, Official Gazette nos. 94/13 and 14/14], which was put into effect on 30 July 2013 and the Mining Act (ZR) [*Zakon o rudarstvu*, Official Gazette nos. 56/13 and 14/14], which was put into effect on 18 May 2013. Besides, various bylaws are governing specific areas of the hydrocarbons sector.

The ZR provides a legal framework for the exploration and production of mineral raw materials in general, whereas the ZIEU contains special provisions concerning the licensing and concession regimes applicable to exploration and production of hydrocarbons (oil, gas and gas condensates).

Following the transposition of the EU Offshore Safety Directive (Directive 2013/30/EU) into national law, the new Croatian Act on Safety of Offshore Exploration and Production of Hydrocarbons (ZSOIEU) [*Zakon o sigurnosti pri odobalnom istraživanju i eksploataciji ugljikovodika*, Official Gazette no. 78/15] entered into force on 25 July 2015, but will become fully applicable as of 19 July 2018. The new offshore legal regime establishes a minimum set of rules for preventing major accidents in offshore oil and gas operations and limiting the consequences of such accidents. In order to ensure the timely implementation of new offshore safety rules, the ZSOIEU provides for additional transitional periods (for further information, please see question 3.11 and 14.1 below).

The Strategic Environmental Impact Assessment (SEA) must be conducted when exploration and exploitation of hydrocarbons are intended. Projects related to the production of oil and gas are subject to an Environmental Impact Assessment (EIA). The EIA approval, issued under the EIA Regulation [*Uredba o procjeni utjecaja zahvata na okoliš*, Official Gazette nos. 61/14 and 3/17], has to be obtained prior to the issuance of the location permit.

On an administrative level, the competent authorities are, *inter alia*, MZOE, the Ministry of Economy (*Ministarstvo gospodarstva*; MINGO), the Ministry of State-owned Property (*Ministarstvo državne imovine*; MDI) as the State administration authority managing State-owned land, MZOE as the State administration authority governing the EIA process and the Ministry of Construction and Physical Planning (*Ministarstvo graditeljstva i prostornog uređenja*; MGPU) as the State administration authority governing the issuance of the location, building and use permits.

In accordance with the ZIEU and the Act on Establishment of the Hydrocarbon Agency [*Zakon o osnivanju Agencije za ugljkovodike*, Official Gazette nos. 14/14 and 73/17], the Croatian Hydrocarbon Agency (*Agencija za ugljikovodike*; AZU) has been established in February 2014. The AZU provides operational support to competent administration authorities in the domain of exploration and production of hydrocarbons and permanent geological storage and it is responsible for, *inter alia*, the launching of a public tender process for the award of a licence for exploration and concession for production, supervision of the licensed activities as well as cooperation with investors, etc.

The ZSOIEU provides for the establishment of a special competent authority, so-called Coordination for the Safety of Offshore Exploration and Production of Hydrocarbons (*Koordinacija za sigurnost pri odobalnom istraživanju i eksploataciji ugljikovodika*; the Coordination body). The Coordination body shall be comprised of the representatives of the different State authorities, such as, *inter alia*, MZOE, AZU, the Croatian Register of Shipping (*Hrvatski registar brodova*; CRS), the Ministry of Maritime Affairs, Transport and Infrastructure (*Ministarstvo pomorstva, prometa i infrastrukture*; MMPI), the National Protection and Rescue Directorate (*Državna uprava za zaštitu i spašavanje*; DUZS) and the Agency for Explosive Atmosphere Hazardous Areas (*Agencija za prostore ugrožene eksplozivnom atmosferom*; Ex-Agency). In accordance with the Regulation on Coordination for the Safety of Offshore Exploration and Production of Hydrocarbons [*Uredba o Koordinaciji za sigurnost pri odobalnom istraživanju i eksploataciju ugljikovodika*, Official Gazette no. 74/17], the Coordination body has been established in September 2017 [http://www.azu.hr/hr-hr/Koordinacija].

Currently, there are 60 production (also called exploitation) concessions of hydrocarbons (57 onshore and three offshore) in Croatia. With the aim of substantially expanding exploration and production activities in the upcoming period, the Croatian Government launched the first international offshore licensing round for the exploration of 29 blocks in the Adriatic Sea, covering approximately 36,823 km², on 2 April 2014. Subsequently, the first international onshore licensing round for the exploration of six blocks across the Drava, Sava and East Slavonia regions, covering approximately 15,000 km², has been opened on 18 July 2014 (further information available at www.azu.hr).

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Oil and natural gas are mineral resources of special interest to the State which are in the possession of the Republic of Croatia. The ZIEU allows investors to apply for rights to explore and extract oil and natural gas reserves. However, only companies having their seat or a branch-office in Croatia or in an EU Member State and which are registered with the competent authority to perform hydrocarbons exploration and production, and which also comply with further statutory requirements set out in Art. 8 of the ZIEU (e.g. payment of all public duties, royalties, charges for the usage of forest land or agricultural land, absence of unlawful exploration and production activities, absence of any remediation liabilities related to the previous exploration and production activities, etc.), may be granted a licence for the exploration and concession for the production of oil and natural gas reserves within one single tendering procedure.

In addition, Art. 6 of the ZSOIEU lists the requirements to be considered when assessing the participants' technical and financial capability, including insurance and liability for potential economic damages. The ZSOIEU explicitly stipulates that the participant may

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be granted a licence only if it complies with all requirements set out in the ZSOIEU and relevant provisions of the EU law.

In accordance with the ZIEU, the State administration authorities competent for conducting the above-mentioned tendering procedure is the MZOE and the AZU in consultation with other competent authorities in case that exploration and production activities are to be carried out in specific areas (e.g. State-owned land, maritime domain, areas under special water regime, etc.).

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

As stated above (see question 3.2 above), the award of the licence and concession agreement for exploration and production of oil and natural gas resources is carried out within one single tendering procedure. The public tendering procedure is launched on the basis of the decision of the Croatian Government. Prior to launching the formal tender procedure, MZOE, in cooperation with AZU, may organise a presentation in order to inform potential investors on hydrocarbons of their potential existence in certain Croatian regions.

The public tender must be published in the Croatian media and internet sites of MZOE at least three months, and in the EU Official Journal at least six months, prior to the expiry of the set deadline for submission of bids. Tender guidance for the first international offshore tender round as well as tender guidance for the first international onshore tender round is being made available at www.azu.hr. The Croatian Government must adopt the award decision within two months.

On the basis of a licence, the investor obtains the right to explore hydrocarbons and to direct the award of the concession in case of a commercial discovery and provided that the investor duly fulfils all obligations from the concluded agreement. The concession forms an integral part of the licence.

The licence may be granted for a maximum of 30 years and covers the exploration period of up to five years and the production period. The exploration period may be extended a maximum of twice for a period of six months in justified cases. The production period may be extended by the Government on the request of the investor, provided that it has been requested at least 12 months prior to the licence expiry.

In accordance with the ZIEU, the following agreements may be concluded between the Government and the investor: (i) an exploration and production sharing agreement (a production sharing agreement); (ii) exploration and production agreement with fees and taxes payments obligation (a royalty payment agreement); or (iii) a mixed agreement containing elements of both agreements under points (i) and (ii). The draft agreement has to be part of the tender documentation. The mandatory terms of the agreement are set out in detail in Art. 22 of the ZIEU. In this respect, it should be noted that the tender guidance for both the offshore and onshore licensing round includes a draft of the production sharing agreement with royalty and applicable taxes (the draft PSA). The ZIEU provides that the above-mentioned agreement has to be concluded between the Government and the investor within three months of the issuance of the licence. However, the onshore PSA with the selected licensees/investors has been signed in June 2016 (please see question 14.1 below), which implies that, in practice, the award of the concession agreement for hydrocarbons exploration and production may be delayed.

In general, the investor pays all costs and bears the risk during the exploration phase of a project. The conditions and methods of reimbursement of expenditures linked to the exploration and production activities shall be regulated in the agreement. If oil and gas is discovered, the investor is entitled to recover its exploration costs. However, if there will be no production, the investor bears all the costs without the right to cost-reimbursement.

Mining activities may be carried out only within the exploration area (*istražni prostor*) and/or within the exploitation field (*eksplotacijsko polje*).

The Croatian Government has the power to revoke the exploration licence and concession for production in case of non-compliance with the terms and conditions of the licence and concession requirements. Grounds for the revocation of the exploration licence are set out in detail in Art. 20 of the ZIEU.

For the construction and operation of mining facilities and installations, the building and use permit are required (Sec. V Arts. 105–139 of the ZR).

The energy activities of gas production and natural gas production are also governed by the ZTP and subject to licensing by HERA. Therefore, if the production (i.e. extraction) operations also include the delivery and sale of natural gas on the Croatian market, a licence for the performance of energy activity of natural gas production (*dozvola za obavljanje energetske djelatnosti proizvodnje prirodnog plina*) is also required. HERA issues the licence only to natural or legal persons who are registered for the performance of the respective energy activity in Croatia and comply with other statutory requirements laid down in Art. 17 of the Croatian Energy Act (ZE) [*Zakon o energiji*, Official Gazette nos. 120/12, 14/14, 95/15 and 102/15] and the Ordinance on Licences for the Performance of Energy Activities and Keeping of the Registry on the Issued and Revoked Licences (PDOED) [*Pravilnik o dozvolama za obavljanje energetskih djelatnosit i vođenju registra izdanih i oduzetih dozvola za obavljanje energetskih djelatnosti*, Official Gazette nos. 88/15 and 144/15] (e.g. technical, expert and financial qualifications, absence of any criminal record, etc.). The licence for natural gas production may be issued for a minimum period of one year and a maximum period of 30 years. The general obligations and rights of a gas producer and a natural gas producer are set out in Arts. 12–13 of the ZTP.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Generally, the new ZIEU allows the Government to participate in oil and gas development projects through a 100 per cent State-owned company (i.e. national special purpose vehicle). In accordance with the ZIEU, such national SPV will be established on a proposal of the Government pursuant to a special law to be enacted by the Croatian Parliament. Furthermore, the Croatian Government has exclusive ownership of the documentation and data in connection with the oil and natural gas development projects.

The draft PSA for both the first offshore and onshore licensing round stipulates that the Croatian State remains the sole owner of all petroleum produced, except as regards the contractor's entitlement to its share of production in accordance with the provisions of the PSA. However, there is no State participation in the PSA. In addition, draft PSA provides for the establishment of an advisory committee, as the competent body of the AZU and MZOE, for the purpose of supervision of the exploration, development and production operations carried out under the PSA.

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3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The investor is required to pay fees and taxes (i.e. royalties) pursuant to the ZIEU, the Regulation on Fees for Exploration and Production of Hydrocarbons (UNIEU) [*Uredba o naknadama za istraživanje i eksploataciju ugljikovodika*, Official Gazette nos. 37/14 and 72/14] and the provisions of the PSA. Participants in the first offshore and onshore licensing round were required to pay an application fee in the amount of EUR 5,000, as well as to provide a bank guarantee for the bid bond in the amount of EUR 500,000.

Methods for setting the amounts and the ratio of allocation of the royalty and other fees for the exploration and production of hydrocarbons are set out in detail under the UNIEU. The fees are established for (i) exploration and production of hydrocarbons, (ii) the storage of hydrocarbons in geological structures, and (iii) permanent disposal of gas in geological structures.

The fees for exploration and production of hydrocarbons consist of:

- **total fees**, which include: (i) a fee for the approved exploration area; (ii) a fee for the area of the established production field; (iii) a signature bonus for the agreement signed between the investor and the Croatian Government; (iv) a fee (royalty) for the produced quantities of hydrocarbons; (v) additional fees for the realised production (production bonus) of hydrocarbons; and (vi) administrative fees; and
- **share of the produced quantities of hydrocarbons**, which shall be expressed in percentage of the produced quantities of hydrocarbons belonging to the Republic of Croatia.

As regards the share of production, please see questions 3.3 and 3.4 above. In accordance with the ZIEU, the Croatian Government enjoys the pre-emption right to purchase the extracted hydrocarbons based on the market conditions depending on the method of production.

3.6 Are there any restrictions on the export of production?

As regards technical restrictions of the Croatian gas transmission system, please see question 1.1 above. In the event of a crisis, certain extraordinary measures (including import and export restrictions) can be taken on the basis of the Croatian Energy Act (ZE) and other energy laws.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

No specific currency exchange restrictions or restriction on the transfer of funds derived from production out of the jurisdiction can be determined in Croatian law. The draft PSA for both the first offshore and onshore licensing round stipulates that all transactions, payments and valuations made in currencies other than the currency of the Republic of Croatia shall be recorded in euros at the exchange rate in effect at the time the transaction or valuation is made. The rate of exchange shall be established by reference to the middle rate published by the Croatian National Bank (*Hrvatska Nacionalna Banka*; CNB).

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

In accordance with the ZIEU, the rights from the licence and agreement may be transferred to a third party; however, the respective transfer is subject to prior approval of the Croatian Government. The Croatian Government cannot refuse the approval without justified reasons. It will be assumed that there is a justified reason for refusal of prior approval in case the investor fails to notify the MZOE of the intended transfer without delay. The MZOE must decide on the investor's application for prior approval within 30 days of receipt of the application. In addition, the Croatian Government has the pre-emption right to acquire a minimum of 10 per cent of the shares from the respective licence and agreement, either via a national SPV or via a legal entity proposed by the Government and which fulfils all statutory requirements for the award of the licence and agreement.

The transfer of rights from the licence and agreement which is carried out contrary to the rules set out in the ZIEU is null and void.

As regards the offshore operations, Art. 6 of the ZSOIEU explicitly stipulates that the licensee may assign its rights and duties from a licence to another mining operator only if it complies with all requirements set out in the ZSOIEU and relevant provisions of the EU law.

As regards the assignment and change of control clauses in the PSA, the draft PSA imposes an obligation for the MZOE's prior approval. A failure to comply with such obligation is specified as a ground for termination of the agreement.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

In accordance with the ZIEU, the investor is obliged to provide the appropriate security or bank guarantee in relation to the exploration and/or production field restoration costs. Additionally, the investor is obliged to have a whole set of liability insurance set out in Art. 43 of the ZIEU which cover specific risks linked to the oil and natural gas development and operation for the duration of the licence and agreement.

In addition, participants in the first offshore and onshore licensing round are required to provide the bank guarantee for the bid bond. Under the draft PSA, two types of financial security are required for oil and gas operations: (i) bank guarantee/performance bond for the works programme; and (ii) insurance for bodily injury, property damage and other losses.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

In accordance with the Concessions Act (ZK) [*Zakon o koncesijama*, Official Gazette no. 69/17], a pledge may be established over the rights from the concession contract, with prior approval of the concession grantor, only in favour of financial institutions to secure the claims of these institutions on the basis of the loan contract. Claims of financial institutions may relate solely to financial instruments acquired for the purposes of the concession contract execution, and shall not include any other claims that financial institutions have towards the concession holder on any other grounds.

Special regulations in connection with the pledge for security or the booking for accounting purposes of rights to develop oil and natural gas are stipulated in the draft PSA for both the first offshore and onshore licensing round. In accordance with the draft PSA, the pledge for security of rights to develop oil and natural gas is subject to prior approval of MZOE. The approval shall not be unreasonably withheld. The respective accounting and auditing procedure is specified in detail in the draft PSA.

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3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Apart from authorisations based on the ZIEU, the ZR and the ZTP (see question 3.3 above), several other authorisations (of different authorities) may be required, depending on the specific project. Therefore, authorisations, e.g. according to the Croatian law on State property management, nature and environmental protection, physical planning and building, water regime and maritime domain, etc., may be required (see question 3.1 above).

Further, for the execution of the mining activities and for the construction of mining facilities and plants, mining projects (*rudarski projekti*) must be developed in accordance with Art. 91 *et seq*. ZR. In addition, pursuant to the ZR, the licensee has to prepare and keep a set of obligatory documents for exploration and production works (e.g. mining plans and certified measurement records, a location plan of the exploration area/production field, a study on hydrocarbon reserves, the mining production project, etc.). The ZR also imposes special obligations of reporting to the competent authorities on the licensee.

Besides having a concession, the holder of the concession for production must also obtain special approval from the MZOE in order to conduct simultaneous offshore hydrocarbons exploration and production activities in Croatia. To obtain the respective approval, the concession holder must comply with requirements set forth in the Ordinance on fundamental technical requirements, safety and security in the exploration and production of hydrocarbons from the Croatian seabed. [*Pravilnik o bitnim tehničkim zahtjevima, sigurnosti i zaštiti pri istraživanju i ekploataciji ugljikovodika iz podmorja Republike Hrvatske*, Official Gazette no. 52/10.]

In addition, the ZSOIEU requires that offshore hydrocarbons operations are conducted only by operators appointed by the licensee and approved by the Coordination body. The ZSOIEU provides for a list of mandatory documents to be adopted by the licensee and/or operators (as an operating company appointed under the PSA between the Croatian Government and the licensee) and/or owners (as an entity responsible for a non-production installation) and submitted for prior approval to the Coordination body. These are, *inter alia*, the corporate major accident prevention policy, the safety and environmental management system applicable to the installation, a report on major hazards, the internal emergency response plan, a design notification (in the case of a planned production installation), a notification of a well operation, a description of the scheme of independent verification, etc. In addition, the report on major hazards is subject to review every three years (Art. 15 (9) and Art. 16 (8) of the ZSOIEU). In the event of 'material changes' affecting the original report on major hazards (as defined in Art. 4 (2) of the ZSOIEU), the operator or the owner will be required to prepare an amended report and to submit such amended report for prior approval to the Coordination body. Guidelines for the preparation and delivery of the above-mentioned documents are being made available at http://www.azu.hr/hr-hr/Koordinacija/Dokumenti.

It should be noted that the competent authorities (e.g. the Coordination body or mining inspectorate) have been given wide enforcement powers in relation to the preparation and carrying out of offshore operations, including the power to prohibit the operation or commencement of operations and to revoke the licences for exploration and production of hydrocarbons (Arts. 21–23 and 35–38 of the ZSOIEU).

As of 1 June 2016, operators and owners will be required to provide detailed information and reports to both the Coordination body and the National Headquarter for Search and Rescue at Sea (MRCC) in accordance with a common data reporting format as set out in the Commission Implementing Regulation (EU) No 1112/2014.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

According to the ZIEU, the movable and immovable property used in oil and natural gas development which can be separated without causing damage is the ownership of the investor who purchased such property. In case the investor already received recovery costs for such property, the Croatian State acquires the ownership over the respective property. In case of the licence revocation and/or termination of the agreement or the licence and/or agreement expiration, the immovable property or other fixed installation on the exploration and/or production field becomes the ownership of the Croatian State.

In addition, the investor is required to undertake all safety measures in order to prevent danger to people, property and the environment on the occupied areas, and also to notify, among others, the Mining Inspectorate and other competent State authorities thereof (Art. 38 of the ZIEU). If the Mining Inspectorate and other competent State authorities ascertain that the safety measures, environmental protection measures and restoration of the exploration and/or production field are sufficient, the investor can obtain a certificate in relation thereto, and thereafter a decision on the decommissioning of the production field and removal from the Registry of production fields. The competent authorities are empowered to prescribe safety measures.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The ZR, the ZIEU and the new Ordinance on permanent disposal of gas in geological structures [*Pravilnik i trajnom zbrinjavanju plinova u geološkim strukturama*, Official Gazette no. 106/13], which came into force on 31 September 2013, provide a legal framework for gas storage in geological structures.

The storage of natural gas is carried out by the PSP (see question 1.1 above) pursuant to the ZTP and Storage Code [*Pravila korištenja sustava skladišta plina*, published by the PSP no. 3/17; available at www.psp.hr], which came into force on 1 April 2017. According to Art. 75 of the ZTP, access to the gas storage system is subject to the regulated third-party access regime. The access to storage can be refused under certain conditions: (i) lack of capacity; (ii) where access to the system would prevent a system operator from performing the public service obligation; or (iii) where access to the system would cause serious financial and economic difficulties to gas undertakings with regard to take-or-pay contracts concluded prior to a request for approval of access, which is subject to prior approval from the regulatory authority (HERA). The refusal has to be notified in writing. The party seeking access to storage can file an appeal with HERA, if access to storage is refused. HERA has to find whether the prerequisites for refusal of access apply (within 60 days). Against the decision of HERA, no appeal is allowed, but the injured party may bring a claim before the competent Administrative Court.

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Gas storage is regulated energy activity performed as a public service. Exceptionally, Art. 6 of the ZTP provides that the energy activity of gas storage may be performed as a market activity, provided that the gas storage operator obtains a prior approval from HERA. According to Art. 6 of the ZTP, the criteria for issuing the approval of HERA is determined taking into account the level of competition in relation to energy activity of gas storage in the Republic of Croatia and the region as well as the issues of security of gas supply in the Republic of Croatia. HERA is required prior to issuing the respective approval to obtain prior opinion of the MZOE and the Croatian Competition Agency (*Agencija za zaštitu tržišnog natjecanja*; AZTN). So far, no such criteria for determining the access to gas storage system have been issued.

The gas storage tariff regime is based on HERA's Methodology for Determining Tariffs for Gas Storage [*Metodologija utvrđivanja iznosa tarifnih stavki za skladištenje plina*, Official Gazette no. 22/14], which came into force on 20 February 2014. On the basis of the methodology, in December 2016, HERA adopted the Decision on gas storage tariff rates for the second regulation period 2017–2021 [*Odluka o iznosu tarifnih stavki za skladištenje plina,* Official Gazette no. 122/16] for PSP, which entered into force on 1 January 2017.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

As regards the Croatian gas market-opening process, please see question 1.1 above. According to the draft PSA for both the first offshore and onshore licensing round, the investor shall be required, on the request of AZU, to sell a set volume of its share of oil and/or gas to the Republic of Croatia if the Croatian Government's production share is insufficient to meet domestic supply requirements. In case of war or imminent expectation of war or grave national emergency, the MZOE may also request all or part of the oil and gas produced from the agreement area and require the investor to increase such production to the extent required.

Cross-border sales and deliveries of natural gas are transacted pursuant to bilateral agreements between the parties and the availability of cross-border capacity. Also, the Rules on the Gas Market Organisation [*Pravila o organizaciji tržišta plina*, published by the HROTE no. 3/17; available at www.hrote.hr], which came into force on 1 April 2017, and the new Transportation Network Rules [*Mrežna pravila transportnog sustava*, published by the PLINACRO nos. 3/17 and 12/17; available at www.plinacro.hr], which will come into force on 1 April 2017, are applicable. In the event of a crisis, certain extraordinary measures (including import and export restrictions) can be taken on the basis of the ZE, the Decision on Plan of Interventions on Measures of Protection of Security of Gas Supply of the Republic of Croatia [*Odluka o donošenju Plana intervencije o mjerama zaštite sigurnosti opskrbe plinom Republike Hrvatske*, Official Gazette no. 78/14] and the Regulation on Criteria for the Acquisition of the Protected Customer Status in the Event of Gas Supply Crisis [*Uredba o kriterijima za stjecanje statusa zaštićenog kupca u uvjetima kriznih stanja u opskrbi plinom*, Official Gazette no. 65/15], which have been adopted in accordance with Regulation (EU) No 994/2010 on Security of Gas Supply. In addition, certain reporting/registration obligations to the CNB may also be required, depending on the specific transaction.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

As regards the obligation of the oil producer to supply the domestic market under the draft PSA, please see question 4.1 above. Cross-border sales and deliveries of oil and oil products are transacted pursuant to bilateral agreements between the parties. In the event of a crisis, certain extraordinary measures (including import and export restrictions) can be taken on the basis of the ZE and the Act on Oil and Oil Derivatives Market (ZTNND) [*Zakon o tržištu nafte i naftnih derivata*, Official Gazette nos. 19/14 and 73/17], which came into force on 20 February 2014. Generally, producers, importers and traders of oil and oil products have an obligation to report certain transactions to the MINGO according to the new Ordinance on Data Delivery by the Energy Undertakings to the Ministry [*Pravilnik o podacima koje su energetski subjekti dužni dostavljati Ministarstvu*, Official Gazette nos. 132/14 and 16/15], which came into force on 20 November 2014. In addition, certain reporting/registration obligations to the CNB may also be required, depending on the specific transaction. As regards the wholesale of oil products, see question 10.2 below.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

As regards ownership of transportation pipelines and storage facilities, see questions 1.1 and 2.1 above. Gas transportation and storage of natural gas are regulated energy activities performed as a public service. Provisions on the operation of gas transportation pipelines and storage facilities can be found in the ZE, ZTP and the Transportation Network Rules, the General Conditions of Natural Gas Supply [*Opći uvjeti opskrbe plinom*, Official Gazette nos. 158/13 and 74/17] and other gas-related regulations. PLINACRO as the TSO owns and operates the network of main transmission lines and regional gas pipelines by which domestic and imported natural gas is transmitted to exit measuring-reduction stations where the gas is delivered to gas distribution systems and to final (industrial) customers directly connected to the transmission system. The operation of a gas transmission network is divided in five regions (eastern, central, northern, western and south Croatia). The TSO has to comply with the duties imposed by the ZTP (Art. 27 *et seq*. of the ZTP incl. informational duties towards gas market participants, publishing terms and conditions governing the use of the network, elaborating the 10-year network development plan, operating, maintaining and developing the transmission facilities, transmitting gas on the basis of signed contracts, etc.). PLINACRO as the TSO is responsible for the allocation and reservation of the transportation system capacities. Network users (e.g. gas supplier and gas trader) are entitled to use the gas transportation system within a reserved capacity on the basis of a gas transportation contract concluded with PLINACRO as the TSO. The system operator is obliged to publish the general terms and conditions of the transportation system and the standard form of gas transportation contract. A tariff charging regime applies to the transportation system both at the transmission and distribution level. Croatia has adopted the entry-

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exit transportation tariff system. In line with ZTP, the unbundling process of the activities related to the gas transmission and gas storage was carried out. As regards operation of storage facilities, see question 3.13 above.

According to the ZTP, the natural gas producer is required, *inter alia*, to: ensure a secure, reliable and efficient operation of the upstream pipeline network; and ensure fair, equal and transparent conditions for access to the upstream pipeline network, including access to plants providing additional technical services, except those parts of the upstream pipeline network used for the production of gas at the gas field site, etc. According to Art. 73 of the ZTP, access to the upstream pipeline network is subject to the negotiated third-party access (TPA) regime. The negotiated TPA is based on negotiated commercial conditions. The gas producer may refuse access to the upstream pipeline network under certain conditions set out in Art. 75 (1) of the ZTP.

According to the ZTNND, energy undertakings performing the activity of pipeline transport of oil (JANAF) and oil products transport by product-pipeline are required to grant access to their transport facilities to parties entitled to transport facilities access at non-discriminatory and transparent conditions pursuant to the negotiated third-party access. As of 20 February 2014, the negotiated third-party access is based on negotiated commercial conditions. Provisions on the operation of the oil pipeline system of JANAF can be found in the Technical Conditions of Access to Transportation Capacities of JANAF [*Tehnički uvjeti za pristup transportnim kapacitetima JANAF-a*, Gazette "Glasilo VRED-a" no. 3-4/03]. Access can be denied under certain conditions (Art. 5 of the ZTNND). There are currently a total of 21 companies licensed for oil and oil product storage in Croatia.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

According to the Croatian building law, both a location permit and building permit issued by the MGPU are required for, *inter alia*, (i) international and main oil and natural gas transportation pipelines including the terminal and associated infrastructure, (ii) underground gas storage, (iii) oil and liquid oil products storage facilities with a capacity of 50,000 tonnes or more, (iv) LPG storage facility with a capacity of 10,000 tonnes or more, and (v) buildings and other projects within strategic investment projects of the Republic of Croatia defined under a special law (e.g. LNG terminal on the island of Krk in the North Adriatic). An EIA must be carried out before a location permit can be issued. The use permit will be issued on the basis of a technical examination, provided that the constructed building satisfies all conditions under the building and other energy-related laws.

Depending on the specific project, several other authorisations and approvals (of different authorities) may be required (e.g. according to the Croatian law on State property management, nature and environmental protection, physical planning and building, water regime and maritime domain, etc.). The operation of oil and natural gas transportation pipelines and associated infrastructure is subject to licensing.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

According to Art. 40 of the ZE, energy entities are entitled to use properties belonging to third parties for the construction and maintenance of grids and systems for the transmission and/or transport and distribution of energy, in compliance with special regulations. Private land may be expropriated provided that this is required with a view to construct a pipeline and that it is in the State's interest to do so. According to Art. 4 of the ZE, construction, maintenance and the use of energy objects as well as the performance of energy activities are considered to be in the State's interest. Generally, construction of new transportation infrastructure has to be provided for in the network development plan of the system operators (Art. 8 of the ZE), but also in the development plans of the local and regional self-government units. Detailed provisions on the administrative procedure applicable to property expropriation can be found in the new Croatian Act on the Expropriation and Determination of Compensation [*Zakon o izvlaštenju i određivanju naknade*, Official Gazette nos. 74/14 and 69/17], which came into force on 26 June 2014.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

The operator of the system to which the customer wishes to be connected is obliged to grant non-discriminatory access at regulated tariffs in line with the Transportation Network Rules (see questions 6.1 and 6.6). The contract on connection to the transportation system is concluded between PLINACRO, as the TSO, and the distribution system operator, storage system operator, gas producer or final (industrial) customer directly connected to the system in line with the General Conditions of Natural Gas Supply. The system operator is obliged to publish the standard form of contract on connection to the transportation system.

As regards access to the oil transportation system, see also questions 6.1 and 6.6.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

As regards the Croatian oil and gas transportation network, see questions 1.1, 3.1 and 6.1. The TSO is obliged to cooperate with other system operators in the gas sector. The Transportation Network Rules sets out specific provisions in relation to development, construction and maintenance of the transportation system. Interconnection of the gas transportation system and transportation system of the neighbouring country, including technical aspects in relation to planning, construction and operation of the interconnected pipelines, is carried out on the basis of the agreement concluded with the transportation system operator of the neighbouring country (see Sec. III and VI of the Transportation Network Rules).

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

As stated above (see question 6.4 above), non-discriminatory access

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to the gas transportation system according to the principle of regulated third-party access is provided for in line with the Transportation Network Rules. The access can be refused under certain conditions: (i) lack of capacity; (ii) where access to the system would prevent the system operator from performing the public service obligation; and (iii) where access to the system would cause serious financial and economic difficulties to gas undertakings with regard to take-or-pay contracts concluded prior to a request for approval of access, which is subject to prior approval from the regulatory authority (HERA). The system operator which refused access to the system on the basis of a lack of capacity or a lack of interconnection shall make the necessary changes and expansion of the system in order to enable access within a reasonable period of time, as far as it is economically feasible to do so or when a potential customer is willing to pay for them. In case of the refused access to the distribution or transmission system by a final decision, construction of a direct gas pipeline may be allowed, which is subject to prior approval from HERA (Art. 74 of the ZTP). Major new gas infrastructures (i.e. interconnectors, gas storage system and LNG facilities) may, upon request, be exempt from the application of third-party access right under certain conditions laid down in Art. 78 of the ZTP.

In August 2017, HERA adopted the Criteria for issuance the approval for construction and operation of a direct gas pipeline, which entered into force on 10 August 2017 [*Kriteriji za izdavanje suglasnosti za izgradnju i pogon izravnog plinovoda*, Official Gazette no. 78/17].

In June 2014, HERA adopted the Methodology for Determining Fees for the Connection to the Gas Distribution or Transmission System and for Increasing the Connection Capacity [*Metodologija utvrđivanja naknade za priključenje na plinski distribucijski ili transportni sustav i za povećanje priključnog kapaciteta*, Official Gazette no. 76/14], which entered into force on 25 June 2014. On the basis of the methodology, in December 2016 HERA adopted the Decision on the respective fee amounts for the regulation period 2017–2021 [*Odluka o naknadi za priključenje na plinski distribucijski ili transportni sustav i za povećanje priključnog kapaciteta za regulacijsko razdoblje 2017. - 2021. godina*, Official Gazette no. 122/16], which entered into force on 1 January 2017.

As stated above (see question 6.1), access to the upstream pipeline network is subject to the negotiated TPA regime. The gas producer may refuse access to the upstream pipeline network under certain conditions set out in Art. 75 (1) of the ZTP.

Non-discriminatory access to the oil transportation system, according to the principle of negotiated third-party access, is provided for in line with the ZTNND and the Technical Conditions of Access to Transportation Capacities of JANAF (see also question 6.1 above). Access can be denied under certain conditions, e.g. lack of capacity, technical or safety limitations (Art. 5 of the ZTNND).

The refusal of access has to be notified in writing. The party seeking access to the system can file an appeal with HERA, if access to the system is refused. HERA has to find whether the prerequisites for refusal of access apply (within 60 days). Against the decision of HERA, no appeal is allowed, but the injured party may bring a claim before the competent Administrative Court.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Under Croatian law, gas transportation is regulated energy activity performed as a public service. The General Conditions of Gas Supply stipulate certain specific data that the gas transportation contracts concluded between gas suppliers or gas traders with the TSO for a definite period of time need to comprise as follows: (i) data regarding the contracting parties; (ii) conditions of gas transmission; (iii) provisions on quality of gas supply; (iv) conditions of gas delivery limitation; (v) provisions on the reading and communication of metering data; (vi) provisions on the billing and payment of the fee for the use of the transmission system; (vii) time and location of gas delivery; and (viii) other provisions. The gas transmission tariff regime is based on HERA's Methodology for determining tariff rates for gas transportation [*Metodologija utvrđivanja iznosa tarifnih stavki za transport plina*, Official Gazette nos. 85/13, 158/13 and 118/15], which regulates the mode, method and conditions of the calculation of the network tariffs. The regulation model is based on the regulation incentive method (i.e. the revenue cap method). The tariff system is based on the entry-exit model. The tariff rates for the natural gas transmission are determined for specific entry and exit points for particular years of the regulation period. The duration of the first regulation period is three years (from 2014 to 2016) and of the subsequent regulation periods five years. The actual tariff rate is set by the TSO, with the prior approval of HERA. In the event that HERA refuses to give approval, it shall independently set the tariff rates. On the basis of the methodology, in December 2017 HERA adopted the Decision on gas transportation tariff rates for the second regulation period 2018–2021 [*Odluka o iznosu tarifnih stavki za transport plina,* Official Gazette no. 127/17] for PLINACRO as the TSO, which entered into force on 1 January 2018.

As of 20 February 2014, oil transportation by oil pipeline is no longer regulated energy activity and the negotiated third-party access is not based on the tariff system for oil transportation. The price for oil transportation by pipeline is based upon negotiated commercial conditions. The price of oil and oil products storage is not regulated; it is based upon existing market conditions.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Gas transmission and distribution are regulated energy activities performed as a public service. PLINACRO, as the only TSO, is legally unbundled (see also question 1.1 above). According to HERA's licence registry, a total of 35 companies are currently licensed as DSOs. Thirteen (13) DSOs are legally unbundled from retail and 22 DSOs are exempt from unbundling due to having less than 100,000 customers. Transmission and distribution networks are subject to regulated third-party access (see questions 6.6 and 7.3).

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Apart from the licence issued by the regulatory authority (HERA), a concession for gas distribution or a concession for the building of a distribution system is required to operate a distribution network. Prior to the granting of a concession, a tendering process has to be conducted in accordance with the requirements set out in the ZTP and the ZK.

A concession may be granted for a minimum period of 20 years and a maximum period of 50 years (instead of the current maximum time limit of 30 years). In addition, the existing concession contracts may be prolonged with prior approval from HERA and in accordance with the requirements set out in the law. The authority has the power to revoke the concession in case of non-compliance with the terms and conditions of the concession requirements (Art.

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41 of the ZTP). According to the Regulation on the amount and method of payment of fees for the concession for gas distribution and concession for the building of distribution systems [*Uredba o visini i načinu plaćanja naknade za koncesiju za distribuciju plina i koncesiju za izgradnju distribucijskog sustava*, Official Gazette no. 31/14], a compensation fee for the concession for gas distribution and concession for building of distribution systems is determined in the amount of 0.5 to 1.5 per cent of the total turnover realised by gas distribution activities in the previous year in the area for which the concession is granted.

Depending on the specific project, several other authorisations and approvals (of different authorities) may be required (e.g. according to the Croatian law on State property management, nature and environmental protection, physical planning and building, water regime and maritime domain, etc.).

7.3 How is access to the natural gas distribution network organised?

Non-discriminatory access to the distribution network, according to the principle of regulated third-party access, is provided for in line with the ZTP and the Distribution Network Rules [*Mrežna pravila plinskog distribucijskog sustava*, Official Gazette nos. 155/14 and 43/17], which came into force on 1 January 2015. The Distribution Network Rules govern, *inter alia*, the connection to the distribution system, services of the DSO, the rights and duties of the DSO, system users and final customers, contractual relationships and general terms and conditions of the distribution system, etc. The network user shall conclude a gas distribution contract with the DSO. The gas distribution contract governs the provision of gas distribution service, including the ancillary services and the financial obligations in accordance with the Distribution Network Rules. Such contract shall also include a list of all final customers connected to the distribution system to which the gas supplier supplies the gas elaborated by the balancing groups. The DSO is obliged to publish the standard form of a gas distribution contract.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Access to the distribution system may be denied by the DSO under certain conditions provided by the law. The regulatory authority (HERA) can be appealed to if the right of access is damaged (see question 6.6 above). Compare also question 6.6 to insufficient system capacity or insufficient interconnection.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The gas distribution tariff regime is based on HERA's Methodology for determining tariff rates for gas distribution [*Metodogija utvrđivanja iznosa tarifnih stavki za distribuciju plina*, Official Gazette no. 104/13], which set out the mode, method and conditions of the calculation of the network tariffs. The regulation model is based on the regulation incentive method (i.e. the revenue cap method). The tariff system in the distribution system is based on the post stamp principle. The actual tariff rate is set by the DSO, with the prior approval of HERA. In the event that HERA refuses to give approval, it shall independently set the tariff rates. On the basis of the methodology, in December 2017 HERA adopted the Decision on gas distribution tariff rates for the second regulation period 2018–2021 [*Odluka o iznosu tarifnih stavki za distribuciju plina* Official Gazette no. 127/17] for the 35 DSOs, which entered into force on 1 January 2018.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

There are no restrictions or limitations in relation to acquiring an interest in a natural gas utility, or the transfer of assets forming part of the distribution network.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Croatia has implemented the entry-exit model as of 1 January 2014. There is currently no commodity exchange or gas hub in Croatia. Wholesale gas trading is exclusively based on bilateral contracts. In order to pursue gas trade activity in Croatia, a licence for trading, issued by HERA, is required. In case the intended activities of wholesale trading of gas also include the sale of gas to end-customers, a licence for supply, issued by HERA, is required.

The ZTP has established the responsibility of the gas market participants pursuant to the balancing group model for the purposes of the smooth execution and calculation of purchase and sale transactions on the gas market, ensuring the compliance of gas volumes delivered into and taken from the transmission network, and separation of the financial transactions from the physical gas delivery.

Each gas market participant, except for the Croatian energy market operator (*Hrvatski operator tržišta energije*; HROTE) as the gas market operator, is required to be a member of the balancing group. A balancing group is a virtual association of one or more gas market participants, organised on a commercial basis, primarily for the purpose of optimising the costs of balancing, for which the balancing party is responsible. The balancing group is organised and managed by the responsible balancing party, and comprised of the direct members (i.e. gas supplier and gas trader) and indirect members (i.e. final customer). The HROTE keeps the register of the responsible balancing parties and publishes it on its website (www.hrote.hr).

The VTP has also been introduced in the gas market in Croatia as of 1 January 2014. Rules on the VTP are laid down under the Rules on the Gas Market Organisation and Transportation Network Rules.

The VTP under Croatian legislation is defined as a point of gas trading after its entry into the transmission network and prior to its exit from the transmission network – including the gas storage system. To trade on the VTP it is not required to book entry-exit capacity or storage system capacity.

Please note that only a responsible balancing party (*voditelj bilančne skupine*) who is a transmission system user is entitled to trade on the VTP. This means that, in fact, only market parties in possession of a supply or trade licence and who have signed a transport contract with the TSO can gain access to the VTP.

The HROTE publishes on its official website the form which allows for the placement of a bid for the purchase or sale of gas on the VTP.

Trading at the VTP is done independently between the responsible balancing parties; neither the TSO nor the HROTE act as a clearing

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house, hence every party bears the counterparty risks of the other. The parties can use bespoke agreements or the standard agreements published on the HROTE's website.

Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (REMIT) applies directly to parties engaging in gas trading in Croatia. Since Art. 9 of the REMIT imposes an obligation on wholesale energy market participants entering into transactions that are required to be reported to the Agency for Cooperation of Energy Regulators (ACER) to register with the competent national regulatory authority, the registration of market participants is made available by HERA via the Centralised European Register of Energy Market Participants (CEREMP) as of 25 February 2015.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas can be traded as an unbundled commodity, separate from the service of distribution/transportation.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Currently, no LNG facilities exist in Croatia. As regards the planned construction of the LNG terminal on Island of Krk in the North Adriatic, please see question 1.1 above.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

According to the Croatian building law, a location permit and building permit issued by the MGPU are required for, *inter alia*, an LNG terminal (see question 6.2 above). An EIA must be carried out before a location permit can be issued. The use permit will be issued on the basis of a technical examination, provided that the constructed building satisfies all conditions under the building and other energy-related laws.

Depending on the specific project, several other authorisations and approvals (of different authorities) may be required (e.g. according to the Croatian law on State property management, nature and environmental protection, physical planning and building, water regime and maritime domain, etc.). The operation of an LNG facility is subject to licensing.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Pursuant to Art. 6 of the ZTP, an LNG facility operation is regulated energy activity which is carried out as a public service in the gas sector. Currently, there are no special regulations of the price or terms of service in the LNG sector.

Pursuant to Art. 87 of the ZTP, the Rules for Use of LNG Terminals (*Pravila korištenja terminala za UPP*) shall set out specific provisions in relation to the development, manner of management and the usage of the LNG terminal including contractual relations and general terms and conditions for using the LNG terminal. In the process of adopting the Rules for Use of LNG Terminals, the LNG terminal operator shall ensure adequate participation of all interested parties, and conduct public consultations lasting no less than 15 days. The Rules for Use of LNG Terminals are to be adopted by the LNG terminal operator, with prior approval of HERA. The respective rules must also be published on the websites of HERA and the LNG terminal operator. Rules for Use of LNG Terminals still remain to be adopted.

In November 2017, HERA adopted the Methodology for Determining Tariffs for LNG Reception and Dispatch [*Metodologija utvrđivanja iznosa tarifnih stavki za prihvat i otpremu ukapljenog prirodnog plina*, Official Gazette no. 110/17] which entered into force on 23 November 2017. The regulation model is based on the regulation incentive method (i.e. the revenue cap method). On the basis of the methodology, in December 2017 HERA adopted the Decision on indicative tariff rates for the LNG reception and dispatch for the regulation period 2020–2039 [*Odluka o indikativnim iznosima tarifnih stavki za prihvat i otpremu ukapljenog prirodnog plina*, Official Gazette no. 127/17] for LNG Croatia, which entered into force on 1 January 2018.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

A non-discriminatory third-party access regime also applies to LNG terminals. The access to a LNG facility can be refused under certain conditions (set out in question 3.13 above).

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The oil industry falls under the competence of MZOE. The national regulatory authority is HERA. The entity responsible for maintenance of the compulsory stocks of crude oil and oil products in Croatia is AZU (formerly HANDA). Beside the ZE, the main legal act is the ZTNND (see question 2.1 above).

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

As stated above (see question 2.1 above), most of the trade in oil products and LPG is carried out by INA Group companies. Other important market players in the oil industry are PETROL HRVATSKA d.o.o., CRODUX DERIVATI DVA d.o.o., LUKOIL Croatia d.o.o. and TIFON d.o.o.

A licence for the performance of energy activities (*dozvola za obavljanje energetske djelatnosti*) issued by HERA is needed to carry out the wholesale of oil products and wholesale of LPG. As regards the wholesale and retail trade with third countries of certain oil products and biofuels, beside the licence for performance of the respective energy activities, it is necessary to obtain approval from MINGO in line with the Regulation on Conditions for Wholesale and Retail Trade with Third Countries of Particular Goods [*Uredba o uvjetima za obavljanje trgovine na veliko i trgovine s trećim zemljama za određenu robu*, Official Gazette nos. 47/14 and 62/15]. According to this Regulation, legal and natural persons engaged in wholesale and trade of fuels (not including oil products and biofuels from the EU Member States, EEA Member States or Turkey) must have adequate warehouses specially furnished and equipped for the storage of fuel. As regards certain reporting obligations to the MINGO, see question 5.1 above.

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The price of oil and oil products is not regulated; it is based upon existing market conditions. Exceptionally, Art. 9 of the ZTNND provides that the Croatian Government may, for the protection of consumers, market regulation or other justifiable reasons, determine the maximum retail prices for certain oil products for a continuous period for a maximum of 90 days.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

On an administrative level, HERA is competent for the regulation and supervision of energy activities in the oil and natural gas market. The competence of other authorities being responsible for anti-competitive practices, such as the Croatian Competition Agency (*Agencija za zaštitu tržišnog natjecanja*; AZTN), remains unaffected.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The regulator has to observe the criteria of the Croatian Competition Act (ZZTN) [*Zakon o zaštiti tržišnog natjecanja*, Official Gazette nos. 79/09 and 80/13] and also that of the Act on the Regulation of Energy Activities (ZRED) [*Zakon o regulaciji energetskih djelatnosti*, Official Gazette no. 120/12] and other energy-related legislation both at the EU and national level.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The AZTN can initiate an investigation upon receipt of a complaint or upon its own initiative. It can request information necessary for conducting the investigation from any entity operating on the market or from State authorities (e.g. HERA is required to provide technical support to AZTN in the form of expert advice and market analysis).

Upon completion of proceedings, AZTN may issue a decision prohibiting further performance of an anti-competitive agreement or practice or a decision prohibiting the abuse of dominant position in the market. AZTN is further empowered to impose fines (of up to 10 per cent of total annual turnover of the party involved in the anti-competitive practice) or remedial measures. In certain circumstances, AZTN can terminate the proceedings by imposing on the parties to the proceedings commitments proposed during the proceedings, provided they are sufficient for the protection of competition and the harmful situation would be eliminated by their fulfilment.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

The Croatian merger control regime catches the merger of independent undertakings, the acquisition of control and the creation of a full-function joint venture. According to Art. 17 of the ZZTN, the filing obligation to the AZTN arises if the following conditions are cumulatively met:

(i) the combined worldwide turnover of all undertakings concerned is at least HRK 1 billion (approximately EUR 131.5 million) in the financial year preceding the concentration, where at least one of the undertakings concerned has its seat and/or subsidiary in the Republic of Croatia; and

(ii) the aggregate national turnover of each of at least two of the undertakings concerned is at least HRK 100 million (approximately EUR 13.15 million) in the same period.

The AZTN may, within a period of 30 days from notification, either clear a merger or decide to open an in-depth review. The in-depth review proceeding may take three months with the possibility of an extension by another three months where it is necessary to seek additional expert advice, carry out an additional analysis or where sensitive industries or markets are concerned. Pursuant to the ZZTN, the AZTN may approve unconditionally or conditionally, or prohibit a merger.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

As stated above (see section 11 above), special requirements or limitations on acquisitions of interests in the oil and natural gas sector may arise from the Croatian and the EU competition law irrespective of the nationality of the purchaser. As an exception, Art. 24 of the ZTP provides that a special certification process must be conducted where a transmission system owner or transmission system operator is controlled by a person from a third/non-EU country. In this context, HERA is required to make an assessment, in consultation with the MZOE and the European Commission, about whether foreign ownership or control of the transmission system would pose a risk to security of supply of the Republic of Croatia and the European Union.

As regards the licence for the exploration and production of hydrocarbons as well as the licence for performance of the respective energy activities, the Croatian law imposes certain residence requirements on the licensees (e.g. please see questions 3.2 and 3.3).

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The regulatory policy in respect of the oil and natural gas sector is especially influenced and affected by the requirements of the European Union Third Energy Package legislation.

Croatia is a member of the Energy Charter Conference. On 1 July 2013, Croatia became the 28th member of the EU.

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13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

As regards dispute resolution procedures applying between the regulator and participants in the oil and natural gas sector, see questions 3.1, 3.13, 6.6 and 7.4 above.

In terms of disputes arising from the PSA between the Croatian Government and the investor, Art. 22 (5) of the ZIEU suggests that the parties are free to agree on dispute resolution (incl. place of arbitration) and on the applicable law. However, pursuant to Art. 97 of the ZK, the dispute arising from concession contracts shall be resolved by arbitration in Croatia (so-called domestic arbitration) irrespective of the fact that a concession holder is a foreign legal entity. If the parties have not arranged to settle disputes by arbitration, dispute falls within the scope of the exclusive jurisdiction of a Croatian commercial court according to the seat of the concession grantor.

In this context, the draft PSA for both the first offshore and onshore licensing round for licences for the exploration and production of hydrocarbons provides that all disputes arising out of or relating to the PSA shall be finally settled by arbitration in accordance with the Rules of Arbitration of the Permanent Arbitration Court with foreign element at the Croatian Chamber of Commerce with a seat of arbitration in Zagreb, Republic of Croatia.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

The New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards was ratified in 1981, and the Convention on the Settlement of Investment Disputes between States and Nationals of Other States was ratified in 1998.

Under the Shareholders' Agreement 2009, MOL gained operational control of INA. Although the shareholders' agreement committed the Croatian Government to take over the gas trading business of INA (i.e. the import business of PRIRODNI PLIN) by December 2010, this issue remains unsolved during the ongoing negotiations between the Government and MOL. Consequently, two arbitration procedures in connection with the INA-MOL dispute were initiated. At the end of November 2013, MOL initiated the arbitration procedure under ICSID rules against the Croatian Government under the Energy Charter Treaty. In January 2014, the Croatian Government initiated arbitration under UNCITRAL rules in Geneva to annul the 2009 Amendments to the Shareholders' Agreement and the Gas Master Agreement (and its First Amendment). In June 2014, the former Croatian Prime Minister was sentenced to imprisonment for taking a bribe from MOL in 2008 in exchange for securing MOL's dominant position in INA. However, in July 2015, the Croatian Constitutional Court annulled the verdict and ordered a retrial. In December 2016, UNCITRAL dismissed Croatia's claims based on bribery, corporate governance and MOL's alleged breaches of the 2003 Shareholders Agreement. ICSID ruling on MOL's claim is still expected.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

Generally, there is no special difficulty in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs. Nevertheless, due to the long timeframes involved in obtaining judgments in court, companies often try to resolve disputes without seeking a judicial remedy.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are not aware of any such dispute resolution cases.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Further liberalisation of the Croatian gas market shall take place in the course of 2018. To this end, a new Gas Market Act is expected to be adopted until March 2018. However, according to the draft proposal made publicly available in December 2017, the deregulation of gas prices for household customers has been postponed (again) in order to protect final (household) customers from the excessive market gas price.

After the parliamentary election in October 2016, the new Croatian Government formed a new ministry for energy and environmental protection. This was done by combining the previous ministries for energy and mining policy and nature and environmental protection, in order to create the new Ministry of Environment and Energy (MZOE). This should enable a "one-stop-shop" for energy and environmental protection policies and, in particular, the permitting process, as it covers the energy sector and environmental protection within a single governmental ministry. In line with the Climate Change Policy and Croatia's Low-emission Development Strategy for the period until 2030, with a view to 2050 (*Strategija niskougljičnog razvoja Republike Hrvatske za razdoblje do 2030. godine s pogledom do 2050. godine*; LEDS), which was developed at the end of 2015, preparation of a new Energy Development Strategy is under way.

In order to further boost investments in exploration and production of hydrocarbons in Croatia, the Croatian Government launched, on 2 April 2014, the first international offshore licensing round for the exploration of 29 blocks in the Adriatic Sea, covering approximately 36,823 km². Pursuant to Decisions of the Croatian Government as of 2 January 2015, a consortium of US-based Marathon Oil and Austria's OMV have been awarded seven offshore oil and gas exploration licences, the company INA obtained two licences, and a consortium of Italy's ENI and UK-based MEDOILGAS

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was granted one licence. However, following the withdrawal of Marathon Oil/OMV consortium from the licensing round in July 2015, the Croatian Government revoked their respective licences. The offshore PSAs with the remaining participants have not been signed yet.

Subsequently, the first international onshore licensing round for the exploration of six blocks across the Drava, Sava and East Slavonia regions, covering approximately 15,000 km², was opened on 18 July 2014 and closed on 18 February 2015. Pursuant to Decisions of the Croatian Government as of 3 June 2015, three companies have been awarded six onshore oil and gas exploration licences. Four licences were awarded to VERMILION ZAGREB EXPLORATION, a local unit of Canada-based energy group Vermilion. One licence was granted to INA, and one to Nigeria-based OANDO PLC. The PSA for five onshore exploration blocks awarded to Vermillion, i.e. INA were signed in June 2016.

Reportedly, the new onshore licensing round for 10 exploration blocks is expected in the course of 2018. However, the prerequisite for this new tender is the adoption of a new Croatian Hydrocarbon Exploration and Production Act (ZIEU), which is currently pending adoption by the Croatian Parliament.

Finally, it should be noted that the implementation of the EU Offshore Safety Directive into national law is still ongoing. Following the adoption of the new Offshore Safety Act (ZSOIEU) in July 2015, further implementing regulation (such as, *inter alia*, the Contingency plan for accidental marine pollution and the Ordinance on investigation of major accidents, etc.) still remains to be adopted in the upcoming period.

As stated above (see questions 3.1 and 3.11 above), the implementation of the ZSOIEU will have implications on the responsibilities and liability of offshore licensees, operators and/or owners of offshore installations in Croatia. Therefore, operators of existing offshore gas installations and operations in Croatia must comply with new regulatory requirements by 19 July 2018.

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Denmark

Windahl Sandroos & Co.

Bo Sandroos

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Natural gas reserves and production

Denmark is one of the leading oil and gas producers in the EU. Oil was discovered offshore in 1966 and production commenced from the North Sea fields in 1972 and gradually increased until a peak in 2004, following which, production has been on the decline. Today, there are 19 producing fields and 15 of them are operated by Maersk Oil (which was acquired by Total S.A.), three fields are operated by INEOS E&P (formerly DONG E&P which was acquired by INEOS in 2017), and one field is operated by Hess (Hess' share of the field has been announced for sale). In 2016, oil production was approximately 298 PJ and gas production was 169 PJ.

As of 1 January 2017, oil reserves are 135 million m^3 and gas reserves are 59 billion m^3. The forecast for oil and gas production is as follows:

	2017	2018	2019	2020	2021
Oil, mill. m^3	8.4	8.2	7.5	6.0	6.0
Gas, bill. Nm^3	3.8	3.5	2.5	1.0	0.9

Transportation, storage, and transmission system

The gas is transported from the fields in the North Sea to the processing plant in Nybro, Jutland. DONG Oil Pipe A/S owns and operates the oil upstream pipeline, whereas the gas upstream pipelines have been taken over by Energinet.dk, the Danish TSO. Once commercial terms have been agreed, Energinet.dk will also take over the oil pipeline.

The gas transmission system onshore is already operated by Energinet.dk. There are two natural gas storage facilities on land, one in Lille Torup, Jutland, and one in Stenlille, Zealand, both owned and operated by Energinet.dk. These two storage facilities are used for seasonal and load balancing and emergency supply.

Distribution

From September 2016, Energinet.dk took over DONG's role as the distributor of natural gas in South Jutland, and South and West Zealand; HMN Naturgas distributes for Central and North Jutland and the Capital Region; and Naturgas Fyn covers distribution on Funen.

Import and export

Denmark is self-sufficient in natural gas, but there is an exchange of gas with Germany, Norway, Sweden and the Netherlands. In 2013, Denmark imported approximately 0.9 mia. m^3 from Germany and Norway, and exported approximately 2.1 mia. m^3 to Sweden, Germany and the Netherlands. For information regarding LNG facilities, please see the answers under questions 9.1 to 9.4 below.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Denmark's total consumption of energy was, in 2016, 749 PJ per year, and approximately 16% thereof is covered by natural gas, i.e. 121 PJ. Over the coming years a substantial part of natural gas consumption could be replaced by non-fossil fuel gases such as biogas.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Denmark is self-sufficient in natural gas with a net self-sufficiency of 121%, but there is an exchange of gas with Germany, Norway, Sweden and the Netherlands.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Denmark is self-sufficient in natural gas, but there is an exchange of gas with Germany, Norway, Sweden and the Netherlands. It is expected that Denmark will, with some interruptions, remain a net exporter of natural gas at least until 2032.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Oil reserves and production

Denmark is one the EU's leading oil producers and the only net

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exporter of oil in the EU. As described in the answer to question 1.1 above, Danish oil reserves and production are located in the Danish sector of the North Sea. There are 19 producing fields and 15 of them are operated by Maersk Oil, three fields are operated by INEOS, and one field is operated by Hess. The five largest oil-producing fields are Halfdan, Dan, Gorm, and Skjold, owned by the DUC consortium (Maersk, Shell and Chevron) and operated by Maersk, and the South Arne field owned primarily by Hess and operated by Hess. These five fields alone produce approximately 80% of the total oil production.

Regulation

The Danish upstream oil sector – as well as natural gas exploration and production – is governed by the Danish Subsoil Act (Act No. 960 of 13th September 2011 as amended by Act No. 535 of 29th April 2015 and with further changes expected to take effect on the 1st January 2018). Under the Act, the state grants a licence to the licensee for investigations, exploration and production. The licence is regulated by the state under the Subsoil Act, which means that all substantial activities in all phases of investigation, exploration and production require a separate approval from the government.

Licences are awarded through licensing rounds, via open door procedures, adjacent area procedures or mini-rounds. Since 1984, seven licensing rounds have been held. The 6th licensing round in 2005 resulted in 14 licences being issued in 2006. Sixteen licences in the 7th licensing round were awarded in April 2016. The Danish Energy Agency (DEA) plans to carry out licensing rounds every second year from 2017 (or more likely 2018) onwards. Licences awarded are exclusive licences for both oil and natural gas exploration and production. The Subsoil Act is supplemented by Model Licences for both tendering rounds and open door procedures as well as model Joint Operating Agreements (JOAs).

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Denmark's total consumption of energy was, in 2016, 749 PJ per year, and 38% thereof is covered by oil, i.e. approximately 287 PJ.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Denmark has, since 1993, been self-sufficient in oil. In 2016, the self-sufficiency percentage was 103% compared to 134% in 2013. Danish oil self-sufficiency has been decreasing since 2004. Please also see the answer to question 2.4 below.

2.4 To what extent is your jurisdiction's oil production exported?

As mentioned in the answer to question 2.3 above, Denmark has, since 1993, been self-sufficient in oil. In 2016, the self-sufficiency percentage was 103% compared to 134% in 2013. Danish oil self-sufficiency has been decreasing since 2004; however, as of 2016, Denmark remains the single net exporter of oil in the EU. It is expected that Denmark will, with some interruptions, remain a net exporter of oil at least until 2026.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The Subsoil Act is a framework act that regulates the general licensing conditions. It governs preliminary investigations, exploration and production of resources from the Danish subsoil with a focus on hydrocarbons.

The purpose of the Danish Subsoil Act is to ensure appropriate use and exploitation of the Danish subsoil, in a manner that is safe and preventative regarding waste, and furthermore to ensure that the accumulation contributes to the Danish energy supply in an expedient matter.

The act is a framework act, which means that licensees need a new licence for each phase of the process. A licence is granted on the basis of a Model Licence which contains detailed terms and conditions and is an integrated part of licensing rounds. The DEA is the responsible authority for granting licences.

Other principal legislation includes the Offshore Safety Act and the Marine Environment Act.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

In accordance with the Danish Subsoil Act, all hydrocarbons in the Danish subsoil are the property of the state. Through licences, for example the 7th licensing round, licences are granted for exploration and production. The legal status of a licence is in Denmark considered private property and is thereby governed by and protected under Danish law.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The Danish Subsoil Act contains several provisions regarding the different stages of oil and gas development.

A licence for preliminary investigations is granted for three years. Such licence is not an exclusive right and it does not prevent the DEA from granting others a similar right. If a company is granted a licence for preliminary investigations, the company is not entitled to the exclusive and sole right for the following licences of exploration for and production of the crude material. Every stage requires a separate licence.

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A licence for exploration and production is a sole and exclusive right, which is granted by the DEA for an exploration period of six years, with an opportunity for extension for exploration of two years at a time, though the full exploration period may not exceed 10 years. The production part of the licence will be for a duration of 30 years, with a maximum of up to 50 years, which may be extended under special circumstances. The exclusive right has two aspects. A positive aspect for the licensee to exercise such an activity (the licence) *vis-à-vis* the state, and a negative aspect in the fact that the licensee needs several permits other than the mere exclusive right in order to carry out development and production of crude materials.

A Model Licence supplements the Subsoil Act and licences for exploration and production of hydrocarbons will be granted on the basis of the Model Licence.

In order for an applicant to be granted a licence, the Subsoil Act lays down requirements for the applicants. An applicant shall have the necessary technical expertise and the financial resources to be granted a licence. Changes to the Subsoil Act in 2015 have in a new chapter 7a implemented new requirements for technical and financial capacity to be assessed and documented at each stage (e.g. seismic, drilling, development, production) and for licensees to provide adequate financial security in the form of insurance or financial guarantees.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

The Danish state's rights are a matter of law. The legislation granting such rights is primarily the Subsoil Act, the Natural Gas Act and the Act on the Danish North Sea Fund, as well as the individual licences. The state participates in licences for exploration and production of hydrocarbons in Denmark through the Danish North Sea Fund (Nordsøfonden), which is owned 100% by the Danish government and designated a special public (state-owned) company. Since 2005, Nordsøfonden has been responsible for a 20% non-operating participation in all licences granted and, furthermore, Nordsøfonden has, since 2012, been responsible for 20% state participation in Denmark's largest producer, the DUC consortium, as a non-operating partner. Nordsøfonden has been, since October 2014, organised as a special public (state-owned) enterprise with its own board of directors. It was previously placed as an entity under the Ministry of Business and Growth.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The Danish Ministry of Taxation, the Central Customs and the Tax Administration are the responsible bodies for corporate income tax and hydrocarbon tax. The revenue is based on reporting by the licensee and supervision from the DEA concerning the metering of the volumes of oil and gas production.

Hydrocarbon extraction is subject to corporate income taxation. The level of taxation is 25% for oil and gas production income. Further hydrocarbon tax is applicable, at a rate of 52%. When calculating the hydrocarbon tax, the corporate tax and a 5% uplift for investments in a period of six years can be deducted. New rules on hydrocarbon taxation have been put forward in October 2017 and are likely to take effect from 1st January 2018.

3.6 Are there any restrictions on the export of production?

Today, there are no such restrictions. In regard to the Act on Notification and Sale Duty concerning Hydrocarbons (Act No. 165 of 7th May 1975), the Minister for Climate, Energy and Building could in principle decide further details regarding the export of production. These rights have never been exercised but formally remain in place.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are no such restrictions other than those applicable to any member of the European Union.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Under Section 29 of the Danish Subsoil Act, any direct or indirect transfer of the licence requires the prior approval of the DEA. The reason is that the DEA must, on behalf of the Danish government, assure itself that the new licence holder can uphold the commitments regarding the licence both from a financial and a technical perspective.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

As in previous rounds, under Sections 30–32 in the Model Licence for the 7th licensing round, the participants must provide the necessary insurances and a financial security (parent company guarantee) that are commensurate with obligations and potential liabilities to be undertaken. Specific insurance guidelines apply in particular regarding third-party liability insurances and control-of-well insurances. As from July 2015, these requirements have been strengthened as licensees will, in accordance with chapter 7a of the Subsoil Act, now have to demonstrate technical and financial capacity at each stage of operations, including development. It remains to be seen how in practice the DEA will administer these rules.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Licences granted under the Subsoil Act cannot be subject to prosecution and cannot therefore be pledged for security according to Section 29 (1) and (2) of the Subsoil Act. A licence to develop hydrocarbons can be booked for accounting purposes, provided the generally accepted accounting principles are adhered to.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

A licence will not be sufficient to carry out work in developing hydrocarbons. In the process it will be necessary to obtain several permissions for the operative work in connection with the licences.

Offshore, it will be necessary to obtain permissions for every significant step of the development in accordance with the Subsoil Act. Furthermore, it will be necessary to have permissions in relation to drilling, environment matters, health, safety and security, residence permits for the workers, flight permits, etc. Some of the

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relevant authorities are the DEA, the Danish Maritime Authority, the Environmental Protection Agency and from 2015 also the Danish Working Environment Authority in matters of health and safety.

Onshore, it will be necessary to obtain construction permissions for processing plants, transportation, transmissions, etc. The Danish municipalities are the main authority for construction and other onshore operational permits outside of the DEA's domains. Onshore, subsoil issues will generally be governed by the DEA, and above-surface issues by the local municipality. Health and safety matters are handled by the Danish Working Environment Authority.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Section 33 of the Subsoil Act contains a provision in relation to decommissioning physical structures onshore and offshore. In the event that the state does not wish to take over the facilities, the licensee must remove the facilities in accordance with the details contained in the decision on decommissioning.

Under Section 37(6) of the Model Licence for the 7th licensing round, which has also been a requirement in previous rounds, a closure plan must be provided in due time prior to the anticipated closure of the facility.

With effect from July 2015, a so-called subsidiary or secondary liability for licensees has been implemented in the Subsoil Act, i.e. a previous licensee will remain liable for decommissioning costs even if ownership has been transferred to a new licensee.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

Chapters 6 and 6a in the Subsoil Act set forth rules on gas storage and CO_2 storage, respectively. The rules are principally similar to those applicable to pre-investigations, exploration and production of oil and gas. All activities for storage require the prior approval of the DEA.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

There are no restrictions on cross-border sales or deliveries of natural gas as long as the general requirements in the Natural Gas Supply Act (Act No. 1157 of 6th September 2016) and the Executive Order (No. 1090 of 6th December 2000) are met.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

There are no restrictions on cross-border sales or deliveries of oil as long as the general requirements in the Pipeline Act (Act No. 277 of 25th March 2014) are met.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Natural gas

The upstream transportation of natural gas in Denmark is regulated by the Danish Natural Gas Supply Act (Act No. 1157 of 6th September 2016) and the Executive Order No. 1090 of 6th December 2000 regarding access to upstream pipelines. The Executive Order states that any interested party is entitled to access the upstream network system against payment. The upstream pipeline system from the natural gas fields in the North Sea to the processing plant in Nybro, Jutland, is owned and operated by Energinet.dk.

Oil

The upstream transportation of oil in Denmark is regulated by the Pipeline Act (Act No. 277 of 25th March 2014 as amended by Act No. 630 of 8th June 2016). According to Section 1 in the Pipeline Act, the owner of the pipeline operates the Danish upstream oil transportation system. The oil is transported from the North Sea platforms to the refinery facilities in Fredericia. Under reference to Section 2 of the Pipeline Act, all oil producers in the Danish part of the North Sea are obliged to use and make payment for the owner's pipeline system. Ownership and the role of operator of the upstream oil and condensate pipeline will be transferred to Energinet.dk.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The establishment and operation of a pipeline and the associated infrastructure must be approved by the DEA in accordance with Section 17 of the Subsoil Act and an environmental impact assessment (EIA) must also be carried out. In relation to the associated infrastructure onshore, it will be necessary to obtain permissions from the involved municipalities, such as zoning and building permits, in addition to the foregoing permits.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

A permit for the establishment and operation of a pipeline must be obtained according to Section 17 of the Subsoil Act. The responsible authority is the DEA. In addition, environmental impact assessments must be made according to the Zoning Act and relevant permits must be obtained from the municipalities. Under the Subsoil Act, government authorities have the powers of compulsory acquisition to facilitate land access.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Please see the answer to question 6.6 below.

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6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Please see the answer to question 6.6 below.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Natural gas

Access to the upstream pipeline network is regulated by Executive Order (No. 1090 of 6th December 2000). An application can be refused in accordance with Section 3, subsection 2 on the grounds listed in subsection 5 (1–3) of the Executive Order. The refusal grounds are if the technical specifications seem incompatible and cannot be solved without difficulty, to avoid difficulties in relation to a harmful impact on the already existing hydrocarbon production, or in order to respect already documented needs for the owner or operator of the pipelines.

Pricing shall be set forth in a non-discriminatory manner and must be reasonable. Third-party access is subject to review by the Danish Energy Regulatory Authority (DERA), which settles disputes under the Executive Order.

Rules are likely to change once ownership and the role of operator of the upstream natural gas pipeline system is transferred to Energinet.dk.

Oil

Access to the upstream pipeline network is regulated by the Pipeline Act, and any user shall pay the owner an amount to cover the capital costs relating to financing the establishment of the oil pipeline with appurtenant pumping and terminal facilities, and any branch pipelines. Further to be paid is an amount to cover other expenditures for the operation of the pipeline as calculated per unit of transported crude oil and condensate. The calculation of such amounts and the further rules for payment are listed in Executive Order No. 803 of 17th June 2016.

In case of a disagreement between the owner and any third party regarding terms and conditions for the transportation, the matter will be settled by the DEA.

According to the law, it is mandatory to use the oil pipeline. The further terms and conditions for use are regulated. To gain access to the oil pipelines requires commercial negotiations. Experience shows that the negotiations can be protracted, and prices and terms are not easily amended.

Further, the DEA has the authority, according to Section 16 in the Subsoil Act, to grant third-party access to facilities other than pipelines and to set forth the terms and conditions for such access where agreement cannot be reached by the parties.

Rules are likely to change once ownership and the role of operator of the upstream oil and condensate pipeline is transferred to Energinet.dk. Furthermore, in October 2017, amendments to the Danish Subsoil Act were put forward that will affect third-party access; these rules are expected to enter into force on 1st January 2018.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Natural gas

The price, terms and conditions are to be negotiated and agreed on between the parties according to Section 5 of the Executive Order. The agreement between the parties must afterwards be reported to the DERA, which supervises such agreements.

The Executive Order is supplemented by (standard) Terms and Conditions for the Transportation of Gas in the Owner's Offshore Pipelines, which are to be entered into by the owner as the transporter and the individual gas producer.

Rules are likely to change once ownership and the role of operator of the upstream natural gas pipeline system is transferred to Energinet.dk.

Oil

The rules for payment and calculation of payments are listed in Executive Order No. 803 of 17th June 2016. The agreement for transportation must be approved by the Minister for Climate, Energy and Building. Disagreement between the parties on terms and conditions for the agreement are to be settled by the Minister for Climate, Energy and Building (this power is delegated to the DEA).

The rules are likely to change once ownership and the role of operator of the upstream oil and condensate pipeline is transferred to Energinet.dk.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

As described in the answer to question 1.1 above, the transmission system is operated by Energinet.dk, while the distribution is divided into regions. The distribution is operated by Energinet.dk as the distributor of natural gas in South Jutland, South and West Zealand, by HMN Naturgas as the distributor for Central and North Jutland and the Capital Region, and by NGF Nature Energy as the distributor on Funen.

The requirements for a transmission company are listed in the Natural Gas Supply Act. A transmission company shall (i) ensure the quality of the natural gas supplied from the transmission system, (ii) ensure the supply of natural gas in Denmark, (iii) co-operate with other transmission companies in Denmark and across borders in order to efficiently exchange natural gas, (iv) prepare plans for the future needs for transmission capacity, (v) ensure sufficient quantities of natural gas, also in light of sustaining the quantities, and (vi) use methods that are transparent, non-discriminating and market-based.

The requirements for a distribution company are also listed in the Natural Gas Supply Act. A distribution company shall (i) inform consumers in regards of the annual consumptions, savings on natural gas and calculate an annual consumption for the area covered by distribution from the company, and (ii) ensure realisation of documented energy savings.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

According to Section 10 of the Natural Gas Supply Act, a licence

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is required to operate a distribution network in Denmark. The Minister for Climate, Energy and Building grants the licences. A licence will be valid for a minimum period of 20 years.

Licences can be granted to companies who fulfil the requirements under Section 28 of the Act. These requirements are that the distributor must have the necessary technical expertise and economic background. The further requirements for access to the transmission system are listed in Section 18 of the Natural Gas Supply Act.

7.3 How is access to the natural gas distribution network organised?

Please see the answer to question 7.1 above.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Section 10a of the Natural Gas Supply Act states that a distributor shall maintain, rebuild, and expand the natural gas network to the extent necessary, and that the Minister of Climate, Energy, and Building can decide further details in relation to the maintenance on the distribution network. The supply of natural gas is considered a universal service. The companies supplying natural gas therefore have a public service obligation towards the consumers.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The fees and conditions for accessing the networks are listed in chapter 7 in the Natural Gas Supply Act. Section 36a states that the fees are determined by the transmission and distribution companies using calculation methods approved by the DERA.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

According to the Natural Gas Supply Act, a distribution network, its assets and shares can only be transferred to the state. The state has an obligation to purchase a distribution network. The state's obligations are carried out by Energinet.dk.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

According to Section 7 (1) under the Natural Gas Supply Act, the consumer of natural gas can freely choose the supplier of natural gas, and all companies with a licence for distribution shall according to Section 7 (5) provide their services for the consumers in an objective, non-discriminative matter.

Gas Point Nordic is the Danish natural gas exchange. Further agreements on transfer of gas between shippers can be made through the Nord Pool Transfer Facility (NPTF). It is a requirement that customers are registered with Gas Point Nordic and Energinet.dk.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

If the requirements in the Natural Gas Supply Act and the Heating Supply Act are adhered to, there are no restrictions on trade of natural gas commodities.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Except for the port of Hirtshals' LNG terminal facilities that can facilitate ships bunkering LNG in Hirtshals, which was opened in July 2015, there are currently no LNG facilities in Denmark. The Natural Gas Supply Act contains the regulatory framework for the LNG facilities. It requires a licence to operate and distribute from a LNG facility in Denmark. Please see the answer to question 7.2 above; the same rule set applies for LNG facilities.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Please see the answers to questions 1.1, 2.1, and 7.2 above, as well as Sections 3, 4 and 6, which are likely also to affect LNG activities.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Please see the answer to question 7.5 above. The same rule set applies for LNG facilities, although differences may occur due to the specifics of LNG.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

The Natural Gas Supply Act contains the same rights for LNG companies as with respect to transmission and distribution companies of natural gas, although differences may occur due to the specifics of LNG.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream oil sector is regulated by multiple different regulatory frameworks in Denmark. There is regulation by the Environmental Protection Act, the Oil Emergency Act, the Petrol Distribution Act, the Competition Act, the Marketing Practices Consolidation Act and applicable tax law also regarding environmental tax. Further regulatory framework may apply according to the different stages in downstream oil.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

In regard to the downstream oil sector, approximately 90% of the

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retail market in Denmark is represented by five companies: Statoil; Shell; Kuwait Petroleum; Uno-X; and OK.

The pipeline infrastructure

Denmark has two refineries: one in Kalundborg; and one in Fredericia. The Kalundborg refinery, owned by Statoil, primarily runs Norwegian crude, but is flexible to run condensates and other crudes. All crude oil, including condensate, is supplied by ship. The Fredericia refinery was in 2016 acquired by Dansk Olieselskab, a private company, from Dansk Shell and processes mostly Danish North Sea crude oil supplied by pipeline from Danish offshore production.

The pipeline connecting the crude oil to the refinery in Fredericia is currently owned and operated by DONG but will be transferred to Energinet.dk. For the regulatory framework, please see the answer to question 10.1 above.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The body in Denmark responsible for competition law analysis, monitoring and enforcement is the Danish Competition and Consumer Authority (DCCA), which endorses larger business mergers and instructs companies to amend or revoke agreements that limit competition.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

As is the case under the EU competition rules, the Danish Competition Act is based on two prohibitions: (1) a prohibition against anti-competitive agreements, etc.; and (2) a prohibition against abuse of a dominant position. The two prohibitions have taken inspiration from Articles 101 and 102 of the EC Treaty, and they are enforced in accordance with the case law of the European Commission, the European Court of First Instance and the European Court of Justice.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The powers of the DCCA include prohibiting or amending agreements and making decisions. Fines for violating Danish competition law are imposed through the judicial system.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Mergers or other changes of control over businesses are typically subject to scrutiny from the Danish competition authorities under Danish competition law, which is strongly influenced by Danish membership of the European Union and EU competition law. These procedures can be lengthy. In addition, the DEA's approval is required for the transfer of licence rights, etc., to third parties. The time for approval will be fully dependent on the circumstances of the case and the individual licence to be transferred.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

Denmark is a member of the European Union and, as such, there are no special requirements or limitations on foreign companies beyond those obligations and limitations described above, found in the Natural Gas Supply Act or the Heating Supply Act.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Denmark is a member of the European Union and, as such, all applicable EU regulations, directives and other measures will apply to Denmark. Denmark is also a signatory to a large number of international treaties and conventions applicable to the oil and gas sectors.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Except for those listed below, there are no special dispute resolution procedures applicable in the oil and gas sectors in Denmark. Referral is made to the Danish rules on civil procedure and the Danish Arbitration Act.

For natural gas, disputes concerning access to the upstream natural gas pipelines including fees and prices will be referred to the DERA with recourse to the Danish Energy Complaints Board.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Denmark is a signatory (1973) to, and has duly ratified into domestic legislation, the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards.

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Denmark is a signatory (1965) to, and has duly ratified into domestic legislation, the Convention on the Settlement of Investment Disputes between States and Nationals of Other States (ICSID).

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

There is no special difficulty in litigating or seeking to enforce judgments or awards against government authorities or state organs in Denmark.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

There have been several instances where foreign companies have been successful in litigation against the government authorities or state organs, for instance within taxation. Denmark has a fully independent judiciary and also a highly developed capacity to handle arbitration cases.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

A political agreement was made in March 2017 regarding the future of the Tyra field which was subsiding due to many years of hydrocarbon production. The political agreement was followed up with an agreement between the government and the owners of Tyra, the D.U.C. consortium, which provided certain tax relief and a compensation scheme. It was stated that legislative proposals would be brought forward no later than in October 2017 – see also below.

The Danish government in July 2017 issued a report on a strategy to increase the potential of Danish oil and gas, increased recovery and value creation. The report had been prepared in collaboration with industry.

In October 2017, the Danish government brought forward proposals to amend the Subsoil Act, the Hydrocarbon Tax Act, the Continental Shelf Act and the Offshore Safety Act.

The proposed changes are primarily a result of the agreements made in March 2017 and relate to hydrocarbon taxation, third-party access to infrastructure and pipelines, approval of capacities in connection with application for new development projects, reservations in the oil pipeline and the separation facilities, safety zones and approval of pipelines in the sea territory. The changes are expected to pass political approval and enter into force on 1st January 2018.

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Further, from 2012–2015 he was an external lecturer at the University of Southern Denmark. He is the author of the book "*Undergrundsloven med Kommentarer*" (2012) and "*The Greenland Mineral Resources Act – the Law and Practice of Oil, Gas and Mining in Greenland*" (2015).

Bo is a law graduate from the University of Copenhagen (1991) and the Nordic Institute of Petroleum and Maritime Law, University of Oslo (1990), and holds an executive MBA from Copenhagen Business School (1995).

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France

Thierry Lauriol

Jeantet

Constance Guyot

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

1.1.1 The Portion of Natural Gas in the French Energy Balance:

Natural gas represents around 15% of the French national energy balance. The demand for natural gas has undergone a considerable expansion over the last 20 years: in France, this demand has doubled, increasing by 57% between 1990 and 2010, whilst the total consumption of primary energy has only gone up by 21%. There was a very marked increase between 1990 and 2005, but it appears that it has since stabilised. The long-term indicative plan of investments in the gas sector for the period 2009–2020 predicted that between 2006 and 2015 the demand for natural gas would clearly decrease, as compared to the demand in the last decade. That being said, however, this demand should nevertheless remain quite important in comparison to the other primary energies (http://www.statistiques.developpement-durable.gouv.fr/publications/p/2668/1009/bilan-gaz-naturel-france-2015-resultats-definitifs.html; "Natural gas balance in France in 2015"; http://www.statistiques.developpement-durable.gouv.fr/publications/p/2669/966/chiffres-cles-lenergie-edition-2016.pdf; "Energy key figures 2016", February 2017; http://www.ladocumentationfrancaise.fr/var/storage/rapports-publics/094000318.pdf; and "Summary of the long-term indicative plan of investments in the gas sector, Period 2009-2020", Ministry of Ecology, Sustainable Development and Energy).

1.1.2 National Production of Natural Gas:

In France, the national production of natural gas represents less than 2% of the total consumption. In 2015, production of raw gas was of 0.164 billion m^3 (compared to 0.148 billion m^3 in 2014) with a coal mine methane volume representing 35% of this gas production. In 2012, production was of 1.08 billion m^3, mostly from the Aquitaine Basin's reservoir, in particular from the Lacq natural gas deposit. Since 2014, the raw gas from the Lacq deposit is exclusively dedicated to Arkema's needs in hydrogen sulfide (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16; Energy and Climate Overview 2016, Exploration and production of hydrocarbons in France, p.71).

In the eighteenth century, the very first gas fields to be exploited were located in Alsace. The gas production that is traded comes almost entirely from Aquitaine, and, specifically, from the Lacq field, which was exploited until October 2013, by Total, which remains today the major gas producer in France. Indeed, as resources are no longer available in the Lacq field, Total had to stop its activity there. However, Total continues the exploitation of the residual gas deposit of Lacq for the supply of the local industry through the project 'Lacq Cluster Chemistry 2030' (LCC30) which was launched in the middle of 2013.

1.1.3 Potential National Reserves of Natural Gas:

Since 2012, some biomethane has been injected into the distribution network of GrDF, in still very marginal quantities but which double every year (82 GWh in 2015, 32 GWh in 2014, against 14 GWh in 2013 and 6 GWh in 2012). It has to be noted that France has the objective of producing 8 TWh of biomethane per year. There is in France a high potential of production of biomethane, which is based in particular on the valuation of the agricultural waste. It should be noted that in 2012, there was only one installation which carried out biomethane injections into the gas networks. However, since March 2016, 18 production sites regularly inject their biomethane into the network (http://www.statistiques.developpement-durable.gouv.fr/publications/p/2669/966/chiffres-cles-lenergie-edition-2016.pdf; "Annual Survey on natural gas market, Results for 2014"; No. 758 April 2016, Ministry of Ecology, Sustainable Development and Energy, p.1).

1.1.4 Importations/Exportations of Natural Gas in France:

With 509.8 TWh, gross inflows of natural gas have declinined by 1.7% in 2015 after a greater decline in 2014 (-5.6%). In 2015, gross inflows by pipeline decreased by 1.9%. From April to October, those gross inflows declined from their 2014 level but they increased during most of the winter months. LNG injections in the network fell for the fourth consecutive year but at a much slower pace than in previous years (-0.7% in 2015 against -19.5% in 2014, -19.2% in 2013 and -32.9% in 2012). In 2015, regasified LNG represented only 12.8% of gross inflow of natural gas, against 28.0% four years ago. Injections at Fos-sur-Mer and Montoir-de-Bretagne now represent respectively 84.7% and 15.3% of the injected LNG in the network after a decline of 9.1% for Fos-sur-Mer and an increase of 12.2% for Montoir-de-Bretagne. The natural gas gets out of the territory under gaseous form through the pipelines' network interconnection points (NIP) with foreign networks, especially Spanish (NIP Pirineos) and Swiss (NIP Oltingue and Jura). After reaching a particularly high level in 2014, outflows fell back significantly in 2015 (-23.4%) to return to a level slightly higher than in 2013. This decrease concerns mainly outflows towards Spain (-35.9%) while those

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towards Switzerland increased (+14.5%). With 446.9 TWh in 2015, the balance of inflow and outflow rose by 2.4%. The share of short-term contracts (less than two years) in gas supplies, which fell to 14.4% in 2013 after soaring to 21.9% in 2014, fell slightly in 2015 (20.9%) due to the resumption of medium-term import contracts. In 2014, prices in the northwest Europe wholesale gas markets have decreased more sharply than the supplies' prices made through long-term contracts resulting in a greater reliance on gas supply markets. During 2015, the gap between the long-term contracts' prices and the price on the gas markets gradually reduced due to the indexation growth of these contracts on gas markets.

Norway maintains its position as the main supplier of natural gas in France with 42.2% of total gross inflows. Russia remains the second-largest supplier, in front of the Netherlands (respectively accounting for 11.4% and 10.7% of total gross inflows). With 9.4% of gross inflows, Algerian LNG is the fourth largest source of supply in France. Qatari LNG continues its decrease begun in 2012 and represents a small part of gross inflows.

(http://www.statistiques.developpement-durable.gouv.fr/publications/p/2668/1009/bilan-gaz-naturel-france-2015-resultats-definitifs.html; Energy and Climate Overview 2016, Exportations, importations, energy invoice, p.62.)

By reason of its geographical position, France is a centre for the transit of gas between the North and the South of Europe, notably to the Iberian Peninsula as well as to Italy via Switzerland.

Gas arrives in France through five (5) principal points of entry (Taisnières, Dunkerque, Obergailbach, Fos-sur-Mer and Montoir-de-Bretagne). The gas entering in transit or "exported" from France occurs principally through three points (via Oltingue on the French-Swiss border and via Larrau and Biriatou towards Spain) (http://www.statistiques.developpement-durable.gouv.fr/publications/p/2669/966/chiffres-cles-lenergie-edition-2016.pdf; "Annual Survey on natural gas market, Results for 2014"; No. 758 April 2016, Ministry of Ecology, Sustainable Development and Energy, pp.1–2).

Gas is transported in France by two operators, "GRT Gaz" (a subsidiary of Engie Energie Services) and, for the South West of France, "TIGF" (Total Infrastructures Gaz France).

Under the double effect of the decrease of total inflows and the increase of outflows, the net balance of imports and exports of natural gas in France decreased from 478.1 TWh in 2012 to 436.6 TWh in 2014, the lowest level since 2002, and finally reached 446.9 TWh in 2015 (http://www.statistiques.developpement-durable.gouv.fr/publications/p/2668/1009/bilan-gaz-naturel-france-2015-resultats-definitifs.html; "French Energy Balance Report", November 2016, p.39).

1.1.5 Storage of Natural Gas in France:

Today, France uses two types of gas storage: storage in water layers; and in salt caverns. The French underground storage facilities are operated by two companies: Storengy, a subsidiary of Engie Energie Services, which manages thirteen (13) sites (including ten (10) in water layers and three (3) water layers), representing 76% of French capacity; and TIGF, a subsidiary of Total, which operates two (2) water layers, providing 24% of French capacity (http://www.cre.fr/reseaux/infrastructures-gazieres/description-generale; General Description).

There are currently significant projects ongoing for the transformation of former deposits of hydrocarbons, which today are exhausted, into gas storage capacity. Many opportunities are currently open.

In 2013, stock levels were lower than those of 2012, until reaching the minimum level of 85.6 TWh at the end of December, which is 7% less than the previous year. As from January 2014, and due to the low levels of filling, the situation reversed, with a level of stock higher than 12% than the one of January 2013.

The mild temperatures during 2014 have contributed significantly to reduced natural gas consumption (http://www.statistiques.developpement-durable.gouv.fr/publications/p/2668/1009/bilan-gaz-naturel-france-2015-resultats-definitifs.html; "French Energy Balance Report", November 2016, p.40).

1.1.6 Methane Terminals in France:

There are currently four methane terminals in France:

- The "Fos-Tonkin" terminal in Fos-sur-Mer (with a re-gasification capacity of 5.5 Gm^3/year) near Marseilles, and the "Montoir-de-Bretagne" terminal near Saint-Nazaire (with a re-gasification capacity of 13 Gm^3/year) which are managed by Elengy, a subsidiary of Engie Energie Services.
- The "Fos-Cavaou" terminal situated at Fos-sur-Mer (with a re-gasification capacity of 8.25 Gm^3/year) managed by Fosmax LNG, a subsidiary of Elengy and de Total Gaz Electricité Holding France (TGEHF).
- The "Loon-Plage" terminal near Dunkerque, which entered into service at the end of 2016 and is managed by Dunkerque LNG (which EDF, Fluxys and Total all hold shares in).

These infrastructures, except the Loon-Plage terminal, are accessible to third parties. Moreover, it should be noted that the methane terminals managed by Elengy are regulated by the Energy Regulation Commission (ERC) (http://www.cre.fr/reseaux/infrastructures-gazieres/description-generale; http://www.engie.com/wp-content/uploads/2012/05/110929-conf-terminaux-du-9-sept-11-sans-intro.pdf).

In 2010, at the Fos-Tonkin terminal, in use since 1972, 128 methane ships were unloaded, representing around 15% of French consumption. More than 30 years later, 2,500 LNG cargoes have been unloaded at the Montoir-de-Bretagne terminal (in use since 1980). The terminals receive around 30% of the natural gas used in France.

An expansion is planned for the Montoir-de-Bretagne terminal for the period 2015 to 2017 and for the expansion of the Fos Cavaou terminal for 2019. The "open season" for the renovation and development of the Fos Tonkin terminal in 2011 has been closed on 18 November 2011 by the allocation of capacity leading to an "Adjusted Horizon 2035 Project" (http://www.elengy.com/en/projects/fos-tonkin-open-season.html; general description of projects).

Projects to increase the regasification capacity are currently under study. They aim notably to develop the capacities of the existing sites: Fos Cavaou (+8.25 Gm^3/year by 2020); and Montoir-de-Bretagne (+2.5 to +6.5 Gm^3/year).

However, the two new projects of Antifer in Le Havre and Fos Faster in Fos-sur-Mer were abandoned (http://www.wk-transport-logistique.fr/actualites/detail/54934/le-terminal-methanier-d-antifer-enterre-par-le-ministre-des-transports.html; http://www.developpement-durable.gouv.fr/IMG/pdf/Panorama_energie_climat_2015_complet_mis_a_jour_le_26_aout_2015.pdf; Energy and Climate Overview 2016, Methane terminals, pp.73–74).

1.1.7 Distribution:

The distribution of natural gas, which is assured by GrDF (Gaz Réseau Distribution France, Engie Energie Services subsidiary), and twenty-two (22) local distribution companies, is an activity which is managed by public bodies through concession contracts, or through service regulations.

Around 9,550 French towns, and almost all towns with more than 10,000 inhabitants, are supplied with natural gas. This provides 80% of the French population with access to gas. The

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distribution networks for natural gas represent a total length of 194,600 km, which places France in second place in Europe (the longest distribution network being in Germany). As stated above, the networks are operated by GrDF and the twenty-two (22) local distribution companies (located for the most part in the South West and in the East) and by Antargaz and SICAE de la Somme et du Cambraisis (two companies which have been recently authorised) through concession contracts, which bind those operators to local bodies (http://www.cre.fr/reseaux/infrastructures-gazieres/description-generale; General Description).

1.1.8 Marketing and Sales of Natural Gas:

The sale of gas is open to competition. Since July 2007, the gas market has been totally open to competition, including with regard to individuals. It means that they are able to choose freely their gas supplier (http://www.developpement-durable.gouv.fr/La-structure-et-le-fonctionnement,10665.html; https://www.ecologique-solidaire.gouv.fr/commercialisation-du-gaz).

The consumption of natural gas in France highly depends on the climate. During the last few decades, the natural gas sector has grown strongly. Between 1990 and 2010, the request for natural gas increased by 57%. However, further to a strong growth in 2011 with 520 TWh consumed, the market has experienced a stagnation and even a reduction since 2012 (https://www.ecologique-solidaire.gouv.fr/sites/default/files/11%20-%20Les%20march%C3%A9s%20p%C3%A9troliers%20et%20gaziers%20mondiaux%20et%20la%20s%C3%A9curit%C3%A9%20d%27approvisionnement.pdf).

The consumption of natural gas remains relatively stable, a stability which is due in particular to the development of the use of the gas in the systems of domestic heating thanks to the implementation of thermal regulations in 2012. These regulations promote the use of gas, which is cleaner than fuel oil and cheaper than electricity, which will favour the gas industry in France in the next years (http://www.cre.fr/marches/marche-de-detail/marche-du-gaz).

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

See the answer to question 1.1.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

See the answer to question 1.1.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

See the answer to question 1.1.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

2.1.1 The Portion of Oil in the French Energy Balance:

Oil is a very important energy source in France: it constitutes nearly 45% of the French Energy Balance. French dependence on oil and gas will remain very important for several decades, despite the accelerated development of energy savings, and the energy transition towards less CO_2-intensive energies and renewable energy. With the target of cutting hydrocarbons consumption by 30% by 2030, France is still overly dependent on hydrocarbons (https://www.ecologique-solidaire.gouv.fr/ressources-en-hydrocarbures-france; https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Key figures energies-climate in France, p.12).

2.1.2 National Production and Potential National Reserves of Oil:

French national production accounts for a very small part of the total consumption. Already in sharp decrease in 2014, exploration investments continued to fall in 2015, with a reduction by a factor of 3.5 in mainland France between 2013 and late 2015. Companies focused on optimising their deposits' production. In 2015, the annual average price of Brent stood at $53.6 billion, which represents a decrease of 46% compared to 2014 ($99.4 billion). The fall of oil prices adds to an already difficult situation for oil exploration and production activities in France.

In 2015, France used 77 million tonnes of oil equivalent (toe) of oil (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Exploration and production of hydrocarbons in France, p.70).

In 2015, crude oil production in France was at 0.84 Mt, which is 11% more than 2014. The geographical breakdown demonstrates a continuing predominance of the Paris Basin, representing 62% of the national production (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Exploration and production of hydrocarbons in France, p.71).

In France in 2015, there were sixty-four (64) oil and gas fields in operation, mainly in the Aquitaine Basin and the Paris Basin (https://www.ecologique-solidaire.gouv.fr/ressources-en-hydrocarbures-france).

At the end of 2015, 46 conventional hydrocarbon exploration licences were currently valid. Twelve exploration licences were granted or extended and four were explicitly rejected. In 2015, the size of valid land exploration licences decreased by 4.425 km², from 24.584 km² to 20.159 km². This 18% reduction results from the decrease of the renewed licences' size.

In 2016, exploration spending forecasts for France were up (around €45 million). Two drillings in the Aquitaine region would represent a third of that amount (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Exploration and production of hydrocarbons in France, p.70).

If the French production of petroleum and gas covers only a small part of the needs of the country, the presence of around 10 companies, which are active in the two principal basins, shows the economic value of this production.

2.1.3 Importations/Exportations of Oil in France:

To cover its oil consumption, France is 99% dependent on imports. Such imports amount to nearly 2 million barrels per day. With regard to gas, more than 98% of the gas consumed in France is imported.

After several consecutive years of decline, French crude oil imports are clearly rising again in 2015 (5.8% and 56.7 million tonnes). Libyan political instability weighed on imports from North Africa which were down by 17% over the year. Thus, France imported more from the Middle East, thanks to a rebound in the Iraqi production, and sub-Saharan Africa (mostly Angola and Nigeria).

The importance of the Organization of Petroleum Exporting Countries (OPEC) continues to increase, reaching 56% of French crude oil imports, its highest level since 1994. The main suppliers of France remain Saudi Arabia, Kazakhstan, Nigeria and Russia.

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Angola has moved up from seventh to fifth place, becoming as important as Algeria. Norway, from which French imports have halved over the past five years, has been downgraded from fifth to eighth place, now appearing just after Azerbaijan (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Importations, exportations, energy invoice, p.63).

2.1.4 Distribution and Transportation:

In 2017, the total sales of road fuel (without GPL), which represent more than half of the total oil consumption, has decreased by 1.3% compared to 2016. The sale of domestic fuel declined sharply by 8.4% between 2016 and 2017. The sales of GNR (non-road diesel), which has replaced heating oil for certain uses since 2011, has increased by 9.6% compared to 2016 (http://www.statistiques.developpement-durable.gouv.fr/publications/p/2668/1399/conjoncture-energetique-deuxieme-trimestre-2017.html; Energy and Climate Overview 2016, The prices and the distribution of petroleum products, pp.155–157).

Transport is ensured by three (3) major crude oil pipelines connecting import deposits and refineries and several finished products pipelines supplying distribution deposits.

The crude oil pipelines are the following: the first one, starting from the seaport of Marseille, the South European pipeline ("PSE" in French), supplies the refinery of Feyzin, Cressier (Switzerland); and the second one, the Antifer-Le Havre pipeline, transports crude oil from the port of Antifer to the deposit of the CIM (*Compagnie Industrielle Maritime*) in Le Havre which supplies refineries of Lower Seine.

The finished products pipelines include the following: the Le Havre-Paris pipeline ("LHP" in French), supplying Paris and Paris airports with finished products, it also serves Caen and Tours; the Mediterranean Rhône pipeline ("PMR" in French), delivering refined products from the port of Fos-sur-Mer to the region of Lyon, the Cote d'Azur and Switzerland (Geneva) from Fos-sur-Mer; the Donges-Melun-Metz ("DMM" in French), crossing France from west to east, from the Port of Saint-Nazaire to Saint-Baussant; and the Common Defense pipeline (*oléoduc de défense commune "ODC"* in French), which is the French part of the CEPS (Central Europe Pipeline System) of NATO and extends over 2,260 km on the French territory (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Transport network through pipelines, p.77).

2.1.5 Storage of Oil in France:

In 2015, France had a total storage capacity of petroleum products of 46 million m^3, which is stable compared to 2014. The capacity for finished products amounts to approximately 29 million m^3.

France has 203 distribution deposits of fuels/combustibles, with a capacity greater than 400 m^3 (excluding deposits of refineries) (http://www.developpement-durable.gouv.fr/IMG/pdf/Panorama_energie_climat_2016_complet-Vdef.pdf; Energy and Climate Overview 2016, Transport network through pipelines, p.78).

Storage facilities are unevenly distributed across the country. Proximity of refining tools, of importation sites and of infrastructure of massive transport of oil products affects this distribution. It should be noted that 15 regions represent less than 15% of national oil storage capacity. Haute-Normandie and PACA represent together 48% of EFS ("*établissements fiscaux de stockage*") storage capacities. Aquitaine and Nord-Pas-de-Calais account for 18% of the capacity. Ile-de-France and Rhône-Alpes, respectively, account for 8.6% and 6.4%, probably due to the importance of economic activities in these two regions (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Transport network through pipelines, p.78).

2.1.6 Marketing, Sales of Oil:

The fuels distributed in France comply with the European Directive 2009/30/EC which determines the characteristics of petrol and gasoil. Moreover, the fuels marketed in France are those authorised by the Decree of 19 January 2016.

The price of dated Brent increased in 2017 compared to 2016 and averaged $52.39/bbl, although it systematically decreased from 2011 to 2016 (going from $111.22/bbl to $43.54/bbl).

As a Member State of the European Union, France has to provide the European Commission data on the average weekly national retail prices of petroleum products according to the framework of the implementation of European Council Decisions 1999/280/EC of 22 April 1999 and the Commission 1999/566/EC of 26 July 1999.

In 2016, the average prices (taxes included) of fuels and domestic fuel in 2015 (calculated from the weekly prices) were set at: 1.30€/l for lead-free; 0.95, 1.10€/l for diesel fuel; and 0.60€/l for domestic fuel (average prices are accessible on: http://www.prix-carburants.developpement-durable.gouv.fr/petrole/se_cons_fr.htm).

Due to the characteristic features of the distribution of domestic fuel (marketing chain, customer service, size and evolution of the market), the average gross margin of transmission-distribution is traditionally higher than that of other fuels. In 2016, it amounted to 11€/l for Eurosuper and 10.3€/l for diesel fuel (https://www.ecologique-solidaire.gouv.fr/carburants-et-combustibles-liquides-ou-gazeux; https://www.ecologique-solidaire.gouv.fr/prix-des-produits-petroliers).

2.2 To what extent are your jurisdiction's energy requirements met using oil?

See the answer to question 2.1.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

See the answer to question 2.1.

2.4 To what extent is your jurisdiction's oil production exported?

See the answer to question 1.1.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

3.1.1 Applicable Legislation:

France adopted a new bill in order to prevent the granting of new exploration permits. The blocking of hydrocarbons exploration in the French Metropolitan territory and its Overseas Departments has been presented in the Climate Plan ("*Plan Climat*") in July 2017 and

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has been adopted by the National Assembly and the Senate during the autumn of 2017. The law provides that no new hydrocarbon exploration licences will be granted, which will stop the search for new oil or gas deposits. Therefore, the requests for exploration permits that have already been submitted can be refused. Existing operating concessions will not be renewed beyond 2040, so production is expected to expire by then. Regarding unconventional hydrocarbons (shale gas), their exploration and extraction with hydraulic fracturing techniques are banned. The only exception is that mine gas will continue to be captured for safety and environmental reasons because it is very dangerous: it is explosive; and contributes strongly to global warming. These provisions apply to both land and sea projects, as well as overseas projects, in the same way as projects in metropolitan France.

In 2015, the law for the transition to more sustainable sources of energy ("*loi relative à la transition énergétique pour la croissance verte*" in French) was adopted and published in the Official Gazette on 18 August 2015 (Law No. 2015-992, dated 17 August 2015). This law aims to help the country to fight against climate change and to increase the energy independence by finding a better balance between its various sources of supply.

The main objectives of this law are the following:

- to reduce CO_2 emissions by 40% by 2030 compared to 1990;
- to reduce the consumption of fossil fuels by 30% by 2030 compared to 2012;
- to increase the share of energy from renewable sources to 32% of France's final energy consumption by 2030 and to 40% of electricity;
- to reduce energy end-use consumption by 20% in 2030 compared to 50% by 2050; and
- to diversify electricity generation and to reduce the share of nuclear in electricity generation to 50% by 2025.

Several implementing decrees were issued since 2 October 2015 (https://www.legifrance.gouv.fr/affichLoiPubliee.do?idDocument=JORFDOLE000029310724&type=echeancier&typeLoi=&legislature=14).

The principal texts applicable to the exploration and the production of oil and natural gas in France are, notably, the former Mining Code, the New Mining Code (legislative section of the New Mining Code codified by Order No. 2011-91, dated 20 January 2011), and the Energy Code (legislative section codified by Order No. 2011-504, dated 9 May 2011 and regulatory section codified by Decree No. 2015-1823, dated 30 December 2015). A reform of the New Mining Code is now under way.

Law No. 2003-8, dated 3 January 2003, relating to the gas and electricity markets and to the public service of energy, Law No. 2004-803, dated 9 August 2004, relating to the public service of electricity and gas and to electrical and gas companies and their texts of application as well as Law No. 2006-1537, dated 7 December 2006, relating to the energy sector, were abrogated in May 2011 and are now codified in the Energy Code.

As regards previous legislation applicable to the oil regime, Law No. 92-1443, dated 31 December 1992, relating to the reform of oil regime was also abrogated in May 2011 by Order No. 2011-504.

Law No. 2011-835 as of 13 July 2011 prohibits the exploration and mining of oil and gas by hydraulic fracturing and repeals exclusive licences to include projects using this technique.

The latest texts adopted in the natural gas sector in France are Decree No. 2016-973 of 18 July 2016 on the provision to public persons of data on transportation, distribution and production of electricity, natural gas and biomethane, oil products and heat and cold, as well as Decree No. 2016-495 of 21 April 2016 on the content of the concession annual report transmitted by natural gas distribution organisations to licensing authorities.

3.1.2 The Holders of the Rights to Explore and to Produce Oil and Natural Gas:

Before the adoption of the new law preventing the granting of new hydrocarbon exploration licences, the exploration and production of natural gas and oil was governed by the provisions of the First Book of the Mining Code, as provided by articles L.411-1 and L.621-1 of the Energy Code. In order to have the right to explore or produce oil and natural gas in France, it was necessary to comply with the provisions of the New Mining Code.

Thus, article L.121-1 of the New Mining Code provides that "*research for the discovery of mines may be undertaken:*

- *either by the owner of the surface area in question or with his agreement, following a declaration to the competent administrative authority;*
- *in the absence of agreement, with the authorisation of the competent administrative authority, once the owner has been formally requested to present his comments, in accordance with the conditions fixed by decree passed by the Council of State ("Conseil d'Etat"); or*
- *by the holder of an exclusive research permit stated in Chapter II of this Section*".

Within the scope of research carried out concerning liquid or gas hydrocarbons, article L.121-3 of the New Mining Code provides that the person that has conducted the research has the right to dispose freely of these products, only if authorised by the competent administrative authority.

In fact, article L.131-1 of the New Mining Code provides that the persons entitled to proceed with the production of oil and natural gas must be holders of a concession, which accords them the right to operate the mines.

3.1.3 Authorities:

The Department of Energy and Climate (in French "*DGEC*") is jointly held by the Ministry of the Ecological and Inclusive and the Ministry of the Economy and Finance. Its function is to develop and to implement policy on energy, energy commodities, and to fight against global warming and air pollution.

The *Bureau Exploration-Production des Hydrocarbures* (in French "*BEPH*"), together with other services, is responsible for managing the "hydrocarbons" mineral domain in France, which involves attribution of exploration and production for oil and gas, and monitoring of the related activities. It also makes available to the public all data concerning oil-and-gas exploration and production in France, such as mineral rights, geophysical data, well-drilling data and production data (http://www.beph.net/).

The *Bureau de Recherches Géologiques et Minières* (in French "*BRGM*"), as part of its function as the French Geological Survey, is the public reference institution in the Earth Sciences domain, for the management of surface and subsurface resources and risks. BRGM, for the account of the DGEC and delegated by BEPH, has been assigned the task of managing oil-and-gas seismic data and, since 2008, all well-drilling data and, progressively, the data held by the oil and gas companies operating in France (http://www.brgm.fr).

The General Council of Economy, Industry, Energy and Technology (in French "*CGE* "), whose competence was expanded to financial matters in March 2012, was created by Decree No. 2009-64, dated 16 January 2009, merging the General Council of Industry, Energy and Technologies and the General Council of Mines. It is presided over by the Minister of the Economy but is also at the disposal of the Ministry of Ecology, Sustainable Development and Energy. The "*CGE*" is composed of about fifty (50) members, including

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general mine engineers and telecommunications engineers, as well as several other top civil servants. It is composed of four (4) sections: "Technology and Society"; "Innovation, Competitiveness and Modernisation"; "Regulation and Resources"; and "Security and Risks". The Council is assisted by the general inspectorate of the ministry department, which supports the general engineers and carries out missions at the request of the Council (http://www.economie.gouv.fr/cge/actualites).

The *Bureau de Normalization du Gaz ("BNG")*: established in 1970, was authorised by the Ministry of Economy Finances and Industry in February 2011.

According to this decision, the BNG is in charge of:

- standardisation, especially in the field of gas treatment, transportation, distribution and in the use of gas fuels; and
- standardisation applicable to gas infrastructures, gas appliance and components, accessories, gas quality and related services and activities (http://www.afgaz.fr/normalisation-bng and P. Sablière, *Energy Law*, Dalloz Action 2014-105; pp.1367–1368).

3.1.4 Regulatory Authority:

Since 2000, the French energy sector has also had a regulator to ensure that the internal electricity and gas markets are functioning properly (created by the Law dated 10 February 2000). The regulator is the Energy Regulatory Commission ("ERC"). As far as natural gas is concerned, the ERC:

- is the guarantor of the right of access to the networks and natural gas installations;
- monitors the proper functioning and the development of the networks and natural gas infrastructures and liquefied natural gas;
- is the guarantor of the independence of the network managers; and
- contributes to the construction of electricity and the European gas market.

In a more general manner, the law confers upon the ERC the task of monitoring the proper functioning of the electricity and gas markets, as well as exchanges at the frontiers of both gas and electricity.

It should be noted that Decree No. 2012-385 of 21 March 2012 provided for the establishment of a National Commission on guidance, monitoring and evaluation techniques for exploration and exploitation of liquid and gaseous hydrocarbons.

(http://www.cre.fr.)

3.1.5 Initiatives or Policies of the Government:

3.1.5.1 Long-term indicative plan for investments in the gas sector

The drawing-up of this plan is provided for by article 18 of the Law dated 3 January 2003, referred to above. This is in fact a report, presented to the National Assembly, which describes the foreseeable evolution of the demand for natural gas over the next ten (10) years, the adequacy of gas infrastructure (underground storage, methane terminals, transport canalisations, inter-connection works), as well as the contribution of long-term contracts for the supply of the French market.

The 2009-2020 Plan is the second report. The first one was transmitted to the National Assembly in 2006.

(http://www.ladocumentationfrancaise.fr/var/storage/rapports-publics/094000318.pdf; "Long-Term Indicative Plan for Investments in the Gas Sector, Period 2009-2020".)

The multiannual programming on energy ("*programmation pluriannuelle de l'énergie*"), approved by Decree No. 2016-1442 of 27 October 2016, is an essential element of the energy transition:

- it provides opportunities for businesses and allows the creation of green growth jobs;
- it makes irreversible the energy transition and the development of renewable energies; and
- it places France among the first countries in the world to apply the Paris Agreement on Climate Change.

(https://www.ecologique-solidaire.gouv.fr/sites/default/files/PPE%20int%C3%A9gralit%C3%A9.pdf; *La Programmation Pluriannuelle de l'Energie*.)

3.1.5.2 Investment decisions and initiatives of the Government

The investment decisions in the gas sector belong to the operators even though public authorities have several ways to support the development of new infrastructures that are essential for the security of national supply, such as tariff incentives, or temporary derogations to the access of third parties to the infrastructures.

The investment decisions in the oil sector also belong to the operators. It should be noted that no indicative plan for investment in this sector has been set out.

In addition, in order to reduce France's energy dependence and to, as much as possible, reduce oil and gas importations, public authorities have granted hydrocarbons research permits.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The exclusive research permits and concessions are subject to a specific regime provided for in the New Mining Code. Such regime is the same for the development of oil and natural gas reserves, since, as previously mentioned, articles L.411-1 and L.621-1 of the Energy Code provide that their exploration and production is governed by the provisions of the First Book of the New Mining Code.

3.2.1 The Research Regime:

The New Mining law (article L.121-1) distinguishes between three research regimes:

- research carried out by the owner of the land or his successors in title;
- research authorised by the administration; and
- research carried out pursuant to an exclusive research permit.

3.2.1.1 Research carried out by the owner of the land or his successors:

The owner's right to prospect is a consequence of his right of ownership and a normal use of this right. He is, however, not allowed carry out prospective works if his land is within the perimeter of a concession, of an exploitation permit or an exclusive research permit.

3.2.1.2 Research authorised by the administration:

The procedure for the authorisation request is provided for in the Decree dated 14 August 1923 (article 6), as modified by the Decree dated 14 November 2011. Any natural or legal entities, whatever its nationality is, may ask for an authorisation to perform research works.

The request, which is sent to the Prefect ("*Préfet*"), indicates the operation, the nature of the substance that is being looked for and the likely size of the deposit, as well as the numbers of the parcels of land concerned, and the owners, and attempts at amicable settlement. After having been sent to the mines department, the

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request is addressed to the mayor of the local authority where the owners are domiciled in order to enable the latter to be made aware of the contents of the request.

The owners then have 15 days, as from notification of the request, to make known any comments that they may have. At the end of this period the file is returned to the Prefect ("*Préfet*"), who transfers it to the Minister in charge of mines, the latter taking the final decision by way of an order.

3.2.1.3 The exclusive research permit:

The exclusive research permit regime is provided for by articles L.122-1 to L.122-3 of the New Mining Code, as created by the provisions of the Order dated 20 January 2011, relating to the codification of the legislative section of the New Mining Code.

The exclusive research permit for substances that may be conceded is accorded by the administrative authority, after a competitive bid process, for an initial period of a maximum of five years.

The request, with a complete file, is sent to the Minister responsible for mines by a registered letter with an acknowledgment of receipt.

The request is evaluated in accordance with criteria laid down in the New Mining Code and its decree of application. According to article L.122-2 of the New Mining Code, the applicant shall, in particular, justify its technical and financial capacities by providing all of the documents referred to in articles 3 to 6 of Decree No. 2006-648, dated 2 June 2006 (which has been modified by the Decrees dated 14 November 2011 and 30 December 2011).

The permit confers on its holder the exclusive right to carry out all works of research within the perimeter of the aforesaid permit and to dispose freely of the products extracted during the course of the research (article L.122-1 of the New Mining Code).

3.2.2 The Concession:

In accordance with articles L.132-2 to L.132-4 of the New Mining Code, the concession is granted by Decree of the Council of State ("*Conseil d'Etat*"), following a public enquiry and a bidding process.

Article L.132-6 of the New Mining Code provides that only the holder of an exclusive research permit in force may obtain a concession, within the perimeter of the research permit and for the substances mentioned by the permit. In addition, the holder of the exclusive research permit has the right, if the request is made before the expiry of the permit, to grant concessions over the deposits that have been discovered and may be exploited within the perimeter of this permit during the period of the validity of the aforesaid permit.

Article 24 of Decree No. 2006-648, dated 2 June 2006, (modified by article 2 of Decree No. 2016-308 of 17 March 2016) provides a list of the documents that are to be submitted together with the request, which is then sent, once fulfilled, to the Minister responsible for mines by a registered letter with acknowledgment of receipt.

The request for a concession is subject to a public enquiry for a period of 30 days.

In accordance with article L.132-8 of the New Mining Code: "*The institution of a concession, even for the benefit of the owner of the land in question, creates a real property right distinct from the ownership of the surface area. This right may not be subject to a mortgage.*"

The duration of mining concessions is fixed in the concession document. In accordance with article L.132-11 of the New Mining Code, the first period of validity cannot exceed fifty (50) years.

It should be noted that operating concessions will not be renewed beyond 2040.

3.2.3 Mining Permits:

Mention should be made of another mining title, the "Mining Permit", and the regime which applies to it. However, this regime (former articles 50 to 63 of the Mining Code) only applies to permits that are in effect as of the date of the entry into force of Law No. 94-588, dated 15 July 1994, and to the requests for mining permits which have been submitted before this date. It does not therefore apply in terms of future requests.

3.2.4 Specific Provisions:

Mention should also be made that Book VI of the New Mining Code sets out a regime and specific provisions for French overseas territories.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

See the answer to question 3.2.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

In accordance with the New Mining Code and with its articles L.136-1 to L.136-4, the mines or deposits belonging to the State may be operated directly or by State-run entities or by any other method. The State may also allocate new mining titles on these mines or deposits.

The mines which are not operated and which belong to the State may be replaced, by order of both the Minister of Finance and the Minister responsible for mines, where the deposit is open for research.

The administrative bodies, which are responsible for the management of mines that are operated by the State, are subject to the same rights and obligations as private holders of concessions.

3.4.1 Participation of the State in Gaz de France, now Engie Energie Services:

"Gaz de France" (hereafter referred to as "GDF") was created in 1946 following the adoption of a Law dated 8 April 1946 on the nationalisation of electricity and gas. GDF was a public utility company and owned by the State. The Law dated 9 August 2004, referred to above, has opened up to the private sector the shares of GDF, which has become a private limited company in which the State holds more than 70% of the shares (article 24 of Law No. 2004-803, dated 9 August 2004). The Law of 7 December 2006 has modified this participation of the State, which has been reduced to over one-third of the share capital of GDF (article 39 of Law No. 2006-1537, dated 7 December 2006). In July 2008, GDF merged with Suez to create the group GDF Suez. An order dated 9 May 2011 then codified these provisions in articles L.111-67 and L.111-69 of the Energy Code.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

In accordance with article L.132-16 of the New Mining Code, the holders of the concessions for liquid or gas hydrocarbon mines are bound to pay, on an annual basis, a royalty payment to the State at a progressive rate and calculated on the production.

The rates for the royalty payment for oil and gas developments differentiate between former and new productions. Former

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productions refer to quantities extracted, in accordance with traditional methods, from wells that were brought on line before 1 January 1980; other quantities extracted constitute new productions.

Regarding gas, the rate for less than 300 million cubic metres per tranche of annual production amounts to 0% for both former and new productions; for productions of more than 300 million of cubic metres per tranche of annual production amounts to 30% for former productions and 5% for new productions.

Concerning crude oil, the rate for less than 50,000 tonnes per tranche of annual production amounts to 8% for former productions and 0% for new productions; for productions from 50,000 to 100,000 tonnes per tranche of annual production amounts to 20% for former productions and 6% for new productions; for productions from 100,000 to 300,000 tonnes per tranche of annual production amounts to 30% for former productions and 9% for new productions; for productions of more than 300,000 tonnes per tranche of annual production amounts to 30% for former productions and 12% for new productions.

The methods for the application of this royalty are specified in Decree No. 81-373, dated 15 April 1981, relating to the royalty on the production of liquid or gas hydrocarbons.

The taxation of electricity, gas and oil products in France is governed by European law, in particular the European directives 2003/96/EC of 27 October 2003 and 2008/118/EC of 16 December 2008. Directive 2003/96/EC regulates the excise regime, the tax minimum levels and, under certain conditions, exemptions or differentiated tax rates applicable. In France, there are mainly four types of excise regimes on energy: the contribution to the public service of energy (CSPE); the tax on final electricity consumption (TCFE); the domestic tax on natural gas consumption (TICGN); and the domestic tax on energy products consumption (TICPE).

Furthermore, the sale of electricity, natural gas and oil products is subject to Value Added Tax (VAT).

The VAT rate on the consumption of natural gas and oil products is the standard rate. However, a lower rate (5.5%) is applied to all consumers in case of a subscription to the supply of natural gas. In Corsica, the VAT rate on oil products is 13% (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, The tax system on energy, p.170).

3.6 Are there any restrictions on the export of production?

Compliance with obligations of public services and notably the security of supply in France is mandatory.

The Energy Code sets out safeguard measures applicable to all energy sources (oil and natural gas included). Article L.143-1 provides that in case of an energy shortage or a threat to the external trade balance, the government may, for a set period of time, submit to control and allocate, entirely or partially, energy resources and energy resources of all kinds, as well as oil products.

Article L.143-2 further specifies that interests of national defence may also lead to such safeguard measures. This requirement is set out by articles L.1111-1, L.1111-2, L.1141-1, L.1141-2, L.1141-3, L.2141-2 and L.2141-3 of the Code of Defense.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

This is not applicable in France.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Mining titles in France are provided on an *intuitu personae* basis and are only transferable with the approval of the State. However, the new French law on hydrocarbons will prevent the granting of exploration permits in the coming years.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

See the answer to question 3.2.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Article L.132-8 of the New Mining Code provides that a concession may not be mortgaged.

However, it is also provided that mines are immovable property, as well as buildings for the operation of the mines, machines, wells, galleries and other works carried out on site. The machines and tools which are used for the mining are fixtures. Shares or interests in a company or business for the operations of mines are movable property. Raw materials that are mined, supplies and other movable objects are movable property (article L.131-4 of the New Mining Code).

In the absence of any express prohibition provided for by the text, it should be possible for these elements to be the subject of guarantees/sureties.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

In accordance with article L.161-1 of the New Mining Code, "*the research works or operation of a mine must comply with the constraints and the obligations relating to conservation of safety and public health, to the solidity of public and private buildings, to the conservation of ways of communication, the mine and other mines, to the essential characteristics of the surrounding area, land or at sea, and more generally to the protection of natural areas and landscapes, of the fauna and the flora, of biological balances and natural resources in particular of interests mentioned in articles L.211-1, L.331-1, L.332-1 and L.341-1 of the Environment Code, to the interests of archaeology, in particular those listed in the provisions of the articles L.621-30 and L.621-7 of the Estate Code, as well as to the agricultural interests of the sites and the places affected by the works and by the installations relating to the operation. Besides that, they have to make sure the mine is well used and conserved*".

3.11.1 The Control and Monitoring of the Administration:

In accordance with the provisions of articles L.171-1 and L.171-2 of the New Mining Code, the administration is invested with the task of controlling and monitoring mining activities.

The Prefect ("*Préfet*") is responsible for policing the mines. He is under the authority of the Minister responsible for mines and is

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assisted by the regional director for Environment, Land Settlement and Accommodation.

In the exercise of its authority, the Prefect possesses a right of injunction and a right of prohibition.

More specifically, the works that are undertaken by the prospector or the operator may be submitted to authorisation.

3.11.2 The Regulations Governing Research Works and the Operation of Mines:

Article L.162-4 of the New Mining Code provides that the commencement of research works and the operation of mines are subject to administrative authorisation, which is granted following a public enquiry and consultation with the local authorities that are concerned by the works.

Decree No. 2006-649, dated 2 June 2006, relating to mining titles and underground storage titles, repealed Decree No. 95-696, dated 9 May 1995, relating to the commencement of mining works and to the policing of mines. The regime of this authorisation is now determined by the Decree dated 2 June 2006.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

The termination of a hydrocarbon licence is governed by articles L.163-1 to L.163-9 of the New Mining Code.

According to article L.163-2, the termination is subject to a statement to the competent authority (the "Statement").

The concession holder has to notify the measures planned in order to protect the safety, the security and the environment and more generally to stop or prevent all the harmful aspects caused by his activities (article L.163-3 of the New Mining Code).

Pursuant to article L.163-4 of the New Mining Code, if there are no reasonable measures to avoid the harmful aspects, the licence holder has the obligation to research whether there is any significant risk that could threaten the security of assets and people after the termination and, when necessary, identify the appropriate surveillance and control measures which have to be put in place.

Also, the licence holder has to assess the effects of the mining works on the presence, the accumulation, the volume, the discharge, the run-off and the quality of every kind of water and value the effects of the termination on the situation thus created on the downstream users and indicate the measures that have to be taken if necessary (article L.163-5 of the Mining Code).

Articles 43 to 47 of Decree No. 2006-649, dated 2 June 2006, specify the content of the Statement.

The Statement has to be sent to the competent Prefect by registered mail with acknowledgment of receipt and shall be submitted no later than six months before the definitive suspension of the mining works.

Depending on the nature of the works, the following documents are to be enclosed with the Statement:

- The geographical plans of the works subject to the termination at the relevant territorial scales and the corresponding surface.
- If persistence of the risk is observed, the plans, sections and all other documents related to the nature of the deposit and the works carried out.
- A brief accompanied by the plans, exposing the actions taken to date and the next steps planned to minimise the effects of the termination.
- A report on the effects of the mining works and their termination on all kinds of water.
- A study determining whether there would still be significant risk after the final decision of the *Police des Mines*, and in such a case, the prevention and control measures required to mitigate the risks.
- A summary of (i) the plants in which operations have been ceased before the submission of the termination to the procedure, and of (ii) the work and plants having already been submitted to a termination procedure.

The Statement duly completed is also addressed, at the request of the Prefect, to the competent services and city mayors. These services and the local councils of the interested communities have two and three months respectively to submit comments. In relation to the above observations, the Prefect acknowledges the Statement by decree or informs the concession holder of the other measures to be taken. The concession holder has one month to submit any further written comments. The Prefect, after having taken notes of his comments, if any, can prescribe all or part of the abovementioned measures.

In absence of any prescription, within six months, the concession holder proceeds to the termination under the terms set out in the Statement.

The concession holder provides the Prefect with two copies of a report stating the measures taken. After making a record of those measures and confirming their compliance with the additional requirements, if any, the Prefect acknowledges the implementation of the measures by decree. The decree certifies that the concession holder has abided by his obligations to restore the site and constitutes a sort of delivery of a discharge certificate ("*quitus*"). This formality puts an end to the application of the *Police des Mines*.

In addition, Decree of 8 September 2004 provides additional details on the documentation to be attached to the Statement, the techniques used, the effects on all kind of water and the measures generally planned to stop or to prevent all the harmful aspects.

Moreover, the ministerial circular No. 4C/2008/05/10257, dated 27 May 2008, provides detailed prescriptions with regard to the termination of hydrocarbons research works: "*the file concerning the commencement of works has to precise what has to be done at the termination of the works when a borehole is drilled 'dry'*", to achieve "*a final capping program*".

Finally, pursuant to article R.414-19 of the Environmental Code, if the works have been carried out on a "*Natura 2000*" site, the termination has to be subject to an impact assessment.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

In France, provisions concerning gas storage facilities are to be found in a number of important texts. The principal provisions relating to gas storage are as follows:

- Decree No. 2016-1304, dated 4 October 2016, relating to mining works on land and at sea;
- Decree No. 2015-1823, dated 30 December 2015, relating to the codification of the regulatory section of the Energy Code;
- Order dated 28 July 2014 modifying Order dated 2 January 2008, relating to storage containing more than 50 tonnes of flammable liquefied gas under the authorisation regime in accordance with category No. 1412 of the nomenclature of the classified facilities, except for refrigerated or cryogenic storage;

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- Decree No. 2014-328, dated 12 March 2014, modifying Decree No. 2006-1034, dated 21 August 2006, relating to access to underground natural gas storage;
- Decree No. 2014-118, dated 11 February 2014, modifying Decree No. 2006-649, dated 2 June 2006, relating to mining works, underground storage works and to mining and underground storage monitoring authorities and the mining police and underground storages and the annex to article R.122-2 of the Environment Code;
- Decree No. 2011-1411, dated 31 October 2011, relating to geological storage of gas in order to fight against global warming;
- Order No. 2011-504, dated 9 May 2011, relating to the codification of the legislative section of the Energy Code;
- Order No. 2011-91, dated 20 January 2011, relating to the codification of the legislative section of the New Mining Code;
- Law No. 2010-788, dated 12 July 2010, relating to the national commitment for the environment (*"Grenelle 2"*);
- Decree No. 2010-129, dated 10 February 2010, modifying Decree No. 2006-1034, dated 21 August 2006, relating to access to underground natural gas storage;
- Order of 10 February 2010 modifying the Order dated 7 February 2007 relating to profiles and unit rights to storage;
- Law No. 2009-967, dated 3 August 2009, relating to the Grenelle Environment ("*Grenelle 1*");
- Order of 8 February 2008 modifying the Order dated 7 February 2007 relating to profiles and unit rights to storage;
- Order of 2 January 2008 relating to storage containing more than 50 tonnes of flammable liquefied gas under the authorisation regime in accordance with category No. 1412 of the nomenclature of the classified facilities, except for refrigerated or cryogenic storage;
- Order of 7 February 2007 relating to profiles and unit rights to storage;
- Decree No. 2007-910, dated 15 May 2007, modifying Decree No. 2006-648, dated 2 June 2006, relating to mining rights and underground storage rights and Decree No. 2006-649, dated 2 June 2006, relating to mining, the work of underground storage and the regulations governing mining and underground storage;
- Decree No. 2006-648, dated 2 June 2006, relating to mining titles and underground storage titles;
- Decree No. 2006-649, dated 2 June 2006, relating to mining works, underground storage works and to mining and underground storage monitoring authorities;
- Law No. 2006-1537, dated 7 December 2006, relating to the energy sector; abrogated in May 2011 and codified by the Energy Code;
- Decree No. 2005-877, dated 29 July 2005, relating to derogations regarding access to certain gas infrastructures, partly abrogated and codified by the regulatory section of the Energy Code;
- Law No. 2005-781, dated 13 July 2005, fixing the orientations of the energetic policy, partly abrogated and codified by the Energy Code;
- Law No. 2004-803, dated 9 August 2004, relating to public services of electricity and gas and to electrical and gas companies, partly abrogated and codified by the Energy Code;
- Decree No. 2004-555, dated 15 June 2004, relating to technical prescriptions applicable to pipelines and connection of gas transportation, distribution and storage facilities, abrogated and codified in the regulatory section of the Energy Code;
- Order of 17 January 2003 relating to the prevention of major accidents in underground gas storage facilities, liquid and liquefied hydrocarbons;
- Law No. 2003-8, dated 3 January 2003, relating to the electricity and gas markets and to the public service of energy, abrogated in May 2011 and codified by the Energy Code;
- Law No. 2000-108, dated 10 February 2000, relating to the modernisation and development of the public service of electricity, partly abrogated and codified in the legislative section of the Energy Code by Order No. 2011-504, dated 9 May 2011;
- French Mining Code (modified notably by the abovementioned 2003 Law), where there is a section on "underground storage" (Section V *bis*); and
- French Energy Code.

The above list is a non-exhaustive list but indicates the most relevant texts applicable to gas storage. Other provisions that apply may be found in the Environment Code, the Tax Code, the Town Planning Code and in other more specific texts.

The aims of the provisions are the research, the creation, the trials, the development and exploitation of the natural or artificial subterranean cavities, henceforth considered as mining deposits. As regards research, article L.221-1 refers back purely and simply to the provisions of Chapters I and II, Title II, Book I of the code fixing its regime. Article L.252-1 of the New Mining Code specifies that if the subterranean formations searched for are already covered by mining titles, the research is carried out with the consent of the holders of these titles.

The withdrawal of research titles, object of articles L.173-5 and L.173-6 of the New Mining Code, cannot, as far as storage is concerned, be pronounced on the basis of continued inactivity of the research; whilst an insufficient activity can also justify it for other titles.

The exploitation of the storage facilities can only be undertaken by virtue of a concession (article L.231-1). In this regard, the rules of the granting of the title are those provided for the other sites, the reference being made to Section 1 of Chapter II, Title III of Book I of the New Mining Code. The real estate character of the storage and the commercial nature of the act of exploitation are reaffirmed (article L.131-3).

The duration of the concession and extensions are those fixed for all mining concessions (New Mining Code, articles L.132-11, L.132-13, L.142-7 and L.144-4).

As regards the rights and duties of the operator, the principles are practically the same as those for the other sites. However, a special protection is planned to ensure the safety of the underground reservoirs and their exploitation. The carrying out of any works likely to compromise it may be forbidden within a perimeter of protection, as defined by the Decree granting the concession (New Mining Code, article L.264-1). Also, public utility rights of way are established around the works necessary for the exploitation; they are necessarily transcribed in acts for the transfer of real property (New Mining Code, article L.264-1 (2), (3)).

Among the specific obligations of the concessionaire of the storage facility, we note the obligation to comply with the obligations inherent to the public mission of service with which it may be invested and which are specified in the act of concession according to the characteristics of the operation in question; they will be the object of a decree issued in the Council of State ("*Conseil d'Etat*").

As regards the supervision of research and exploitation works, this is assured by the administrative authority in the conditions provided

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for in articles L.171-2, L.172-1 and L.175-1 of the New Mining Code. Accordingly, all the constraints of the mining police have resulted from the Code and decrees taken for the application of the Code apply to storage facilities and, in particular, the Decree dated 2 June 2006, relating to a mining title and underground storage titles (which repealed Decree No. 95-427, dated 19 April 1995, on the policing of mines settling the conditions for the opening and closure of the works).

Chapters III and IV, Title IV of Book I of the New Mining Code apply to storage facilities, such sections referring to the withdrawal of research and exploitation titles, as well as the transfers and leasing of concessions.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

It has to be noted that since the Law dated 3 January 2003, the monopolies of importation and exportation of gas have been removed (article 62 of the aforesaid law).

However, in cases of threat for the supply security of the country in natural gas, the Minister of Energy can order the strictly necessary protective measures, in particular regarding granting or regarding suspension of the authorisations of supply or transport and the concessions of underground storage of natural gas (article L.143-6 of the Energy Code).

4.1.1 Transparency and Regulation:

Historically constructed under the authority of public bodies (the State and local authorities), the works of transportation and distribution of natural gas, as well as the liquefied natural gas installations, constitute the key for the opening up to competition of the gas market. Indeed, competition may only be effected on the markets if the operators and the consumers are able to access these networks, works and installations in conditions that are fair and non-discriminatory.

In this context, the ERC is the guarantor of access to the networks and installations of natural gas and contributes to the construction of an electricity and gas European market. It monitors the proper functioning and the development of the networks and infrastructures for natural gas and the installations for liquefied natural gas and it thus assures a monitoring of the organised markets for natural gas, as well as exchanges at the frontiers for natural gas. Thus, decisions regarding tariffs are taken jointly by the ministers of the economy and energy upon the proposal of the ERC, and notably upon the request of the operators, for the tariffs, for the use of the transportation and distribution networks of gas and the installations of liquefied natural gas (articles L.445-1 to L.445-3, L.445-5, L.446-2 to L.446-4, L.452-1 and L.452-5 of the Energy Code). The ERC therefore proposes to the government tariffs for the use of the networks for the transportation of natural gas, the distribution of natural gas and methane terminals, and it ensures that the tariffs for the use of infrastructures are applied in a transparent and non-discriminatory manner for all users, including with regards to the traditional suppliers.

4.1.2 Public Service Obligations:

Article L.121-32 of the Energy Code puts in place a certain number of public service obligations which are imposed on:

- the operators of the transportation and distribution networks of natural gas and on the operators of the installations of liquefied natural gas, including installations which supply auxiliary services;
- the suppliers mentioned in articles L.443-1 *et seq.* of the Energy Code, on the local distribution companies mentioned in article L.111-54 of the same code and on chartered distributors mentioned in III of article L.2224-31 of the General Local Authorities Code; and
- on the holders of concessions for underground storage of natural gas regulated by the New Mining Code.

These obligations concern, in particular:

- the security of persons and upstream installations for the linking-up to ultimate customers;
- the continuity in the supply of gas;
- the security of supply;
- the quality and the price of products and services provided;
- the protection of the environment, in particular, the application of measures aimed at saving energy;
- energy efficiency;
- the balanced development of the territory;
- the gas supply of last resort to non-domestic clients that ensure missions of general interest; and
- the maintenance, in accordance with article L.115-3 of the Code of Social Action and Families, of a supply for people who find themselves in a precarious situation.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

As previously mentioned in the answer to question 3.6, the Energy Code sets out safeguarding measures applicable to all energy sources (oil and natural gas included) in case of an energy shortage or a threat to the external trade balance.

The said code sets out specific measures for oil since article L.143-7 of the Energy Code provides that the government may regulate or suspend the exportation of crude oil or oil products in the following cases:

1. in the event of a war;
2. in the event of serious international tension constituting a threat of war;
3. in order to carry out obligations it has accepted for the purpose of maintaining peace and international security; and
4. for the implementation of measures taken by the European Union.

The government also imposes an obligation of strategic stocks of oil products listed in article L.642-3 of the Energy Code on licensed oil operators in order to meet the needs of final consumers in periods of crisis.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Until recently, the transportation of natural gas in France was organised in the form of a concession. A new legal regime

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of authorisation for the transportation of natural gas has been implemented in the context of the new gas legislation, and namely, the Law dated 3 January 2003, of which certain provisions have been repealed and modified by the Order dated 9 May 2011. The authorisation for transportation is henceforth granted in accordance with the conditions fixed by Decree No. 2003-944, dated 3 October 2003.

There are today two managers of the transportation networks for natural gas in France: "GRT Gaz" (Engie Energie Services group); and "Total Infrastructures Gaz France" ("TIGF"). The management of a gas transportation network must be carried out by a legal entity, which is separate to the entities that ensure the production or the supply of gas. The transportation companies, which are the result of this legal separation, may carry out any gas storage activity directly in France. The scope of the activities of these companies is determined in accordance with the by-laws of the companies (article L.111-14 of the Energy Code).

As mentioned under section 4.1.1 above, and as far as tariffs are concerned, decisions are taken jointly by the ministers respectively in charge of economy and energy, upon proposals of the ERC, and notably at the request of the operators, for the tariffs for the use of the gas transportation and distribution networks and for the use of the natural liquefied gas installations (articles L.445-1 to L.445-3, L.445-5, L.446-2 to L.446-4, L.452-1 and L.452-5 of the Energy Code). The current regulated tariffs for the use of the gas transportation networks came into force on 1 April 2013 in application of the ERC tariff decision dated 13 December 2012. The sixth tariff for the transportation of natural gas (ATRT6) applies to GRT Gas and TIGF until 31 March 2018 (http://www.cre.fr/reseaux/infrastructures-gazieres/tarifs-d-acces-et-prestations-annexes#section4).

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

Articles L.431-1 and L.632-1 of the Energy Code provide that the construction of hydrocarbon and natural gas transportation pipelines are subject to a procedure of authorisation. As implemented by Order No. 2010-418, dated 27 April 2010, Chapter V of Title V of Book V (section 2) of the Environment Code (articles L.555-7 to L.555-16) specifies the authorisation procedure. It should be noted that the regulatory part of the Environment Code sets out provisions relating to the amendment and the temporary or definitive suspension of the authorisation (R.555-24 to R.555-29).

The operation of natural gas transportation pipelines is subject to a procedure of authorisation, together with specifications, as provided for by the Energy Code (articles L.431-3, L.431-6, L.432-11, L.432-12, L.441-3 and L.453-4 of the Energy Code). According to the type of project in question, this may be an authorisation given by way of ministerial order (Minister of Energy), by order of a Prefect (or "*Préfet*"), or pursuant to a simplified procedure of authorisation given by a Prefect.

The abovementioned Decree No. 2012-615, dated 2 May 2012, equally sets out the details applicable to the construction, commissioning, operation and control of canalisations (R.555-37 to R.555-47 of the Environment Code).

In addition, there are authorisations to be obtained as far as the environment is concerned in application of articles L.511-1 *et seq.* of the Environment Code on installations that are classified for the protection of the environment.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

As indicated in questions 6.1 and 6.2, the construction of the pipelines for the transportation of hydrocarbons and natural gas is subject to authorisation.

The criteria for the granting of authorisations are fixed in an objective, transparent and non-discriminatory manner. Apart from the conditions relating to the technical and financial capacities of the applicant, as well as to safety and the protection of the environment, the criteria also concern the compatibility of the projects with the principles and the missions of a public service.

The owners of land which is crossed by a gas transportation or distribution pipeline must refrain from any action which would harm the construction, the proper usage and the maintenance of the pipeline, in accordance with the conditions fixed by the texts which have been produced in the application of articles L.433-11 and L.433-7 of the Energy Code. Such conditions are fixed by Chapter V of Title V of Book V (section 4) of the Environment Code as regards hydrocarbon pipelines (including oil pipelines). In the event of a threat to the safety of personnel, to the environment or, more generally, in the event of non-compliance with the conditions imposed by the article L.433-16 of the Energy Code, the State, through its representative, has the right to issue an injunction against the operator or the entity responsible for the building works, or, in the event of urgency, a power to suspend operations.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Access of third parties to the gas transportation networks is guaranteed by article L.111-97 of the Energy Code that provides that the persons entitled to access works for the transportation of natural gas, namely and principally, are clients, suppliers and their representatives. In accordance with article L.441-3 of the Energy Code, any transporter of natural gas, any distributor of natural gas and any operator of liquefied natural gas installations may negotiate freely with the supplier(s) its choice of contract for the supply of natural gas and electricity necessary for the operation of its installations provided they have an authorisation.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The transportation of natural gas is effected by gas pipelines. Gas may also be transported by gas tankers as regards liquefied natural gas ("LNG").

As mentioned above, there are two managers of the networks for the transportation of natural gas in France: "GRT Gaz" manages the gas network in the North of the country; and "Total Infrastructures Gaz France" ("TIGF") manages the network in the South West of the country. The transportation of oil is effected by oil pipelines, but is also transported by ship. The new article L.631-1 of the Energy Code (modified by Law No. 2015-992 of 17 August 2015) provides that every person who realises, in metropolitan France, an operation which results in the chargeability of the internal taxes of consumption on a petroleum product listed in article L. 642-3

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or operates in the supply of a petroleum product appearing on this list to aircraft has to prove a maritime transport capacity under the French flag proportional to the quantities released for consumption during the last calendar year.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Access of third parties to the gas transportation networks is guaranteed by articles L.111-97 *et. seq*. of the Energy Code. However, it may be limited or indeed, prevented, if the infrastructures lack adequate available capacity. Any refusal to conclude a contract of access to a method of transportation or distribution of natural gas, or an installation of liquefied natural gas, including the installations providing ancillary services, must set out the reasons for the refusal and this is notified to the applicant and to the ERC (new articles L.111-102 and L.111-103 of the Energy Code).

The development of a competitive gas market therefore necessitates that all the market players can have access, in conditions that are both transparent and non-discriminatory, to detailed information regarding capacity. Thus, the ERC has asked operators, through its decision of 28 May 2003, to publish on their internet site, information relating to their different capacities. This information is published with respect to all entry and exit capacities and in relation to links between balancing zones.

The ERC has also asked operators to produce a general note describing the method of calculation for the maximum capacities that may be sold and to provide details of this method of calculation, as well as the calculations leading to the published results.

Finally, the ERC has asked operators to publish their forecast programme, for the following six-month period, with a reduction in capacity due to maintenance works, with an update at least on a monthly basis.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

See the answer to question 6.4, paragraph 2.

In accordance with article L.445-2 of the Energy Code, the decisions regarding the tariffs for the use of the transportation networks are taken jointly by the Ministers responsible for the economy and for energy, on the basis of the Energy Regulatory Commission.

See also the answer to question 6.1 concerning tariffs.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

In accordance with article L.111-57 of the Energy Code, the management of a network for the distribution of natural gas which supplies more than 100,000 clients on the mainland is assured by entities that are separate from those that carry out activities of production or the supply of natural gas.

The provisions of the Energy Code are close to the former Law dated 7 December 2006, which has therefore (and as compared to the Law dated 9 August 2004) reinforced the idea of the legal separation of activities providing, not for a service or a separate management but distinct legal entities, in order to assure the management activities of the distribution networks and the production activities or the supply of natural gas. Today, there are more than 9,550 (out of a little more than 36,000) French towns supplied with natural gas, which represents only a fairly small proportion of the total number of towns in France but which allows 80% of the French population to have access to gas. Nearly all towns with more than 10,000 inhabitants are supplied with gas.

About 11 million consumers are connected to the gas distribution network. These customers are supplied by 25 distribution system operators (DSO) which are of unequal sizes:

- GrDF ("*Gaz Réseau Distribution France*", subsidiary of Engie Energie Services) supplies over 96% of the market;
- 22 DSOs, also called local distribution companies (LDC), such as Régaz (Bordeaux) and Réseau GDS (Strasbourg) which each ensure the supply of 1.5% of the market. The other 20 LDC share less than 1% of the market.
- Antargaz and SICAE de la Somme et du Cambraisis are the first new entrants on the natural gas distribution sector in France. Their previous activities were, respectively, propane and butane gas distribution and electricity distribution. Their activities in the natural gas sector begun when the networks of the municipality of Schweighouse-Thann (Antargaz), Herbécourt and Vrély (SICAE de la Somme et du Cambraisis) became operational in April 2010 (http://www.cre.fr/reseaux/infrastructures-gazieres/description-generale; "Gas distribution networks").

Article L.432-8 of the Energy Code specifies the missions of the manager of the distribution network.

Article R.432-8 of the Energy Code gives the possibility to the licensor authorities to make a financial contribution to the managers of public distribution networks, to render profitable the operations which increase the density of existing networks and the creation of new public distribution networks.

For towns which are not supplied with gas and which are not linked up to the natural gas network, and which are generally located far from transportation networks of natural gas because they are cut-off from their surroundings, the development of the public distribution network of propane gas may constitute a veritable alternative. Article L.432-6 of the Energy Code confirms the possibility given in 1988 to local bodies and to their public institutions of co-operation to have new businesses for the distribution of propane by the public network, after a period of public consultation, subject to obtaining the approval of the Minister of Energy. A duly accredited company can distribute natural gas or any other combustible gas.

The development of the distribution networks is largely complete. Articles R.432-8 *et seq.* should encourage the creation of new concessions. However, this potential remains fairly limited. The essential interest is to be found today in increasing the number of existing networks, which shall enable the most to be made, in value, of the investments that have already been carried out (Long-Term Indicative Plan of Investments in the gas sector, Period 2009-2020, Ministry of Ecology, Sustainable Development, Transports and Accommodation, http://www.ladocumentationfrancaise.fr/var/storage/rapports-publics/094000318.pdf).

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7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Article L.121-45 of the Energy Code specifies, notably, that the public service of the distribution of natural gas is organised by the State and the local authorities or by their public institutions of co-operation.

The gas "distributors" carry out their activities in accordance with conditions fixed by their authorisation of supply, as well as by the specifications in the concessions or the service regulations of local public bodies referred to in article L.2224-31 of the General Local Authorities Code.

Article L.2224-31 of the abovementioned Code recalls that the local authorities or, if necessary, their public institutions of co-operation, negotiate and conclude concession contracts and monitor the due fulfilment of the public service mission fixed, as regards the granting authorities, by the specifications of these concessions.

The granting authorities assure, in particular, the control of the public distribution networks for gas.

In accordance with the provisions of articles L.322-6 and L.432-5 of the Energy Code, the authorities and institutions referred to above may also be responsible for the works for the development of public networks for the distribution of electricity and gas.

The local authorities, their institutions of co-operation between such local authorities, or their syndicates which do not possess a public distribution network for natural gas, or in relation to which the works are not in the process of being carried out, may grant the public distribution of gas to any company duly accredited for these purposes by the Minister responsible for energy, in accordance with the conditions specified in article L.432-6 of the Energy Code. (These local authorities and institutions may create a public body accepted by the Minister responsible for energy, use an existing public body of this kind, or participate in an existing company, which is privately and publicly owned ("*société d'économie mixte*").)

The acceptance also applies for the firms that wish to distribute natural gas or any other combustible gas through a public distribution network. The approval is delivered according to technical, economical and financial capacities of the business. The conditions and methods for the issue, the maintenance, the withdrawal and the publicity of the approval are specified by Decree No. 2007-684, dated 4 May 2007, abrogated by Decree No. 2015-1823, dated 30 December 2015, on the codification of the regulatory section of the Energy Code.

7.3 How is access to the natural gas distribution network organised?

See the answer to question 7.2.

The right of access to the networks for the distribution of natural gas used to be determined, until recently, by article 3 of the Law dated 3 January 2003. The Order dated 9 May 2011 repealed this article and put an end to this condition of eligible clients.

Any refusal to conclude a contract for access to a distribution network for natural gas, including the installations which provide ancillary services, must provide reasons and be addressed to the applicant and to the ERC.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

In the context of the general monitoring and proper functioning of the natural gas market, the ERC examines refusals regarding access and the contracts or agreements for access to the transportation works and distribution of natural gas, the installations for the storage of natural gas and the installations of liquefied natural gas.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

In accordance with article L.452-1 of the Energy Code, and as for the tariffs for the use of the transportation networks, the decisions relating to the tariffs for the distribution of natural gas are taken jointly by the Minister responsible for the Economy and the Minister responsible for Energy, following a proposal of the ERC, and notably, at the request of the operators. Decree No. 2005-22, dated 11 January 2005, abrogated and codified by the regulatory section of the Energy Code, and an Order dated 14 January 2005 complete the provisions of the Energy Code concerning the tariffs for the use of public distribution networks, as well as the rules applying to these tariffs.

The rates of use of natural gas infrastructure, previously set by Ministers of Economy and Energy on a proposal from the ERC, are now set directly by ERC.

The Energy Regulatory Commission (ERC) fixed the new tariff called "ATRD5". This tariff is defined on the basis of the forecasts of operating costs and investments, the number of customers and the volume of transported gas. It has been applied since 10 March 2016 for a period of about four years.

(http://www.cre.fr/reseaux/infrastructures-gazieres/tarifs-d-acces-et-prestations-annexes; Energy and Climate Overview 2016, Exploration and production of hydrocarbons in France, p.85.)

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

See the answer to question 7.2.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

The activity of the sale of gas to end consumers, which concerns the interface between the distributors and end consumers, is open to competition. It consists either in the retail sale of gas which is purchased wholesale, namely within the context of a long-term supply contract, of between 15 and 20 years, or in the context of a short-term agreement.

2015 was marked by the elimination of regulated tariffs for the sale of gas which was completed in December 2015 for non-domestic consumers (except for small consumers). Gas sale prices on the retail market were down in 2015 due to a decrease of raw material prices. Gas prices in France remain in the average prices of European Union countries and of the eurozone (https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Marketing of gas, p.161).

8.1.1 Retail Trade:

The retail market concerns the end consumers. Clients may opt between two types of contracts:

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- Contracts with regulated tariffs (proposed only by historical suppliers). The regulated tariffs are fixed jointly by the ministers of the economy and energy upon the proposal of the ERC. There are two types of regulated tariffs: subscription tariffs; and public distribution tariffs. Under an agreement with the European Commission approved in January 2013, article 25 of the Law on Consumer, adopted 17 March 2014, the tariffs regulated for non-domestic consumers (excluding small businesses whose level of consumption is less than or equal to 30 MWh per year the small collective housing) have been deleted since 1 January 2016. The opening to competition of the gas market is now very advanced, especially in the market for non-domestic consumers. The market share of alternative suppliers reached 20% in consumption volume for residential customers and 62% for the non-residential segment. The market offers are lowering prices with discounts on the price per kWh up to 15% compared to regulated tariffs.
- Contracts with a market price (proposed by historical suppliers and alternative suppliers). Article L.445-4 of the Energy Code specifies that an end consumer cannot choose contracts with regulated tariffs if it consumes more than 30,000 KW of gas per year. The market prices are freely fixed by the suppliers. After opting for a market price, final consumers of less than 30,000 kWh per year are allowed to return to regulated tariffs according to the previous article L.445-4 of the Energy Code.

(http://www.cre.fr/marches/marche-de-detail/marche-du-gaz.)

8.1.2 Wholesale Trade:

As specified in the answer to question 8.1, France is supplied for the most part on the basis of long-term contracts (between 15 and 20 years).

The price of gas in the context of long-term contracts evolves principally in accordance with the price of oil products (domestic fuel and heavy fuel oil), with a delay of between three and six months.

Gas purchases are generally made through:

- Purchase by agreement, for example by long-term contracts. It is through purchase by agreement that the majority of the gas is imported from Russia, Algeria and Norway.
- The intermediated market, which includes the organised market (Powernext) and brokers.

Exchanges on the wholesale market are operated at the Gas Exchange Points ("GEP"), which are virtual exchange points located at the three balancing zones of the French transmission network. Hence, GEP North is connected to the GRTgaz network while the TRS (Trading Region South) is connected to the south balancing zones of GRTgaz and TIGF. The TRS is the consequence of the merger between the South GEP and TIGF on 1 April 2015. The creation of the TRS improves the functioning of the gas market in the south of France and enables its development. It is a decisive step towards the creation of a single market in 2018. (http://www.cre.fr/marches/marche-de-gros/presentation.)

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas commodities can be traded subject to administrative authorisations. We are not aware of any legal restrictions concerning the trading of unbundled products.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

As far as liquefied natural gas is concerned, we would mention that France has four operational methane terminals (*see* question 1.1, section 1.1.6).

The criteria for the qualification as potential sites for the installation of new methane terminals are both technical (notably with regards to the capacity of reception of a methane gas tanker, to the link-up to the principal transportation network, to the proximity of a high-tension electrical network) and financial (particularly with regards to openings on the national or regional markets, to the part reserved for access of third parties) (http://www.ladocumentationfrancaise.fr/var/storage/rapports-publics/094000318.pdf; Long-Term Indicative Plan for Investments in gas sector, Period 2009-2020, Ministry of Ecology, Sustainable Development and Energy).

In 2016, in the context of an increase of demand, the contribution of the LNG to the French supply correspond to 14% of the French consumption, which corresponds to an average rate of use of infrastructures of the order of 23.1%. The GNL arriving in France comes essentially from Algeria and Qatar, more marginally from Nigeria and purchases on spot-markets.

(https://www.ecologique-solidaire.gouv.fr/sites/default/files/dgec_panorama_energie_climat_16.pdf; Energy and Climate Overview 2016, Gas Infrastructures, The methane terminals, p.87.)

9.2 What governmental authorisations are required to construct and operate LNG facilities?

In order to operate in the liquefied natural gas sector, it is necessary to follow the authorisation procedure provided for by the Energy Code.

It is also necessary to obtain a planning permit, in accordance with the Planning Code. Of course, this concerns an installation which is classified for the protection of the environment.

Accordingly, all the provisions relating to the environment must be complied with and the appropriate authorisations must be obtained.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The tariffs and commercial conditions of use of the liquefied natural gas installations are drawn up jointly by the Ministers responsible for the economy and for energy upon the recommendation of the ERC, depending on public criteria which are objective and non-discriminatory, bearing in mind the characteristics of the service rendered and costs linked to this service (articles L.134-2,4°, L.452-1 *et seq*. of the Energy Code).

Article L.452-6 of the Energy Code provides that: "*The administrative authority may allow, under conditions laid down decree in Council of State, the operator of a liquefied natural gas facility or of an interconnection structure with a natural gas transmission network located in the territory of another Member State of the European Union to depart, for all or part of this facility or structure, from the provisions in this section.*"

The ERC's Deliberation on 18 January 2017 fixed the current tariffs (called ATTM5) applicable since 1 April 2017 for the use of

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methane terminals and for any new subscription from the effective date and for a period of four (4) years.

(https://www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000034299302&fastPos=1&fastReqId=1681321710&categorieLien=id&oldAction=rechTexte.)

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Concerning any third-party access:

- Article L.111-97 of the Energy Code provides that: "*A right of access to the transport and distribution facilities of natural gas, as well as to liquefied natural gas facilities, including the facilities that supply auxiliary services, is guaranteed by the operators that exploit them to customers and suppliers and to their representatives, under conditions defined by the contract.*"

  "*When the operator and the user are not different legal entities, protocols settle the relations between them. These contracts and protocols are sent to the Commission for the Regulation of Energy, at the request of the latter.*"
- Article L.111-98 of the Energy Code provides that: "*A right to access to the facilities defined in article L.111-97 is guaranteed by the operators that exploit them to ensure the execution of the contracts for the transit of natural gas between the big high pressure gas networks within the European economic area.*"
- Article L.111-99 of the Energy Code provides that: "*Networks managers mentioned in III of article L.2224-31 of the General Local Authorities Code have a right to access to natural gas distribution networks in accordance to conditions defined by regulations*".
- Article L.111-100 of the Energy Code provides that: "*Operators shall not discriminate between users or classes of users. Networks managers mentioned in III of article L.2224-31 of the General Local Authorities Code are a special category of users*".
- Article L.111-101 of the Energy Code provides that: "*The exercise of access rights defined in article L.111-97 to L.111-99 cannot preclude the use of structures or facilities by the operator that exploit them in order to perform the public service obligations falling upon it.*"

Moreover, concerning the eligible customers:

- Article L.441-1 of the Energy Code provides that: "*Any customer who uses gas it buys or purchases gas for resale has the right, through its representative, to choose their natural gas supplier.*"
- Article L.441-2 of the Energy Code provides that: "*Every consumer of gas exercises to right provided in article L.441-1 per consumption site.*"
- Article L.441-3 of the Energy Code provides that: "*Every natural gas carrier, any natural gas distributor and every operator of installations of liquefied natural gas negotiate freely with one or several suppliers of his choice the necessary supply contracts of natural gas and electricity for the functioning of his installations, according to competitive, not discriminatory and transparent procedures, such as in particular public consultations or operations in regulated markets*".
- Article L.441-4 of the Energy Code provides that: "*When a consumer exercises the right provided in article L.441-1 for a site, the contract to supply and transportation for this site contracted according to a regulated price is automatically terminated, without compensation to any contractor.*"
- Article L.442-1 of the Energy Code provides that: "*The provisions of articles L.121-86 to L.121-94 of the Consumer Code apply to contracts between natural gas suppliers and consumers or non-professionals for natural gas consumption less than 30.000 kilowatt per year, as well as offers.*"
- Article L.444-1 of the Energy Code provides that: "*The local distribution companies or companies from the legal separation of the activities of local distribution companies and those referred to in article L.2224-31 of the General Local Authorities Code can exercise their right provided in article L.441-1 under the sole supply of all costumers in their service area.*"
- Article L.443-4 of the Energy Code provides that: "*In order to supply clients, are recognized as suppliers the persons installed on the territory of a Member State of the European Community or, within the framework of international agreements, on the territory of another State, which are holders of an authorization delivered by the administrative authority.*"

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The Energy Code sets out a limited regulatory framework in relation to refinery activities and the use of oil products in France.

Such regulatory framework notably relates to technical and security rules applicable to oil facilities, and which are governed by the provisions relating to classified facilities set out by the Environment Code (Title I of Book V).

It also provides that any project relating to the acquisition or the construction of a crude oil refinery, as well as the abandonment or decommissioning of crude oil refinery facilities shall be notified to the administrative authority (article L.641-2 of the Energy Code).

It should be noted that only oil products listed in article 265 *ter* of the Custom Code are authorised in France. The technical rules pertaining to the use of the authorised oil products, as well as their features, are defined by the regulation.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The Energy Code does not set out such framework in relation to oil trading, since 99% of the oil that France consumes is imported.

Notwithstanding, article L.142-10 of the Energy Code provides that each person who receives or sends to or from foreign countries, transports, including by sea, stores some crude oil or petroleum products or distributes petroleum products has to supply to the authority any documents and information on its contribution to the supply of the French market with crude oil and with petroleum products in period of difficulties of supply or directly necessary for the appreciation of the respect for the measures of Books I and VI of the Energy Code or for the respect for the international commitments of France. Law No. 2015-992 of 17 August 2015 adds a paragraph to article L.142-10 which provides that the public authorities have access to the data of consumption of petroleum products, in the respect for measures relative to the information protected by legal or statutory measures.

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11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

Created by Law No. 2008-776, dated 4 August 2008, on the modernisation of the economy, the Competition Authority (the "Authority") replaces the Competition Council which was established by the Order of 1 December 1986. This Order was codified in 2000 in the fourth section of the Commercial Code. The Competition Council had itself replaced the Competition Commission (created in 1977), which replaced the Technical Commission on Cartels and Dominant Positions. Articles 95, 96 and 97 of the Law on the modernisation of the economy, focus on this new Authority and, in this regard, amend the aforementioned provisions of the Commercial Code (http://www.autoritedelaconcurrence.fr/user/index.php).

This transformation, which aimed to close the gap between the French system for regulating competition and the European norm, gathers together responsibilities and resources within a single independent authority.

The Authority is therefore an independent administrative authority, which is specialised in the monitoring of anti-competitive practices, expertise in the operation of markets and the control of merger operations. At the service of the consumer, it has as an objective to monitor the free operation of market forces and to help with the competitive operation of the markets at European and international levels.

The Law on the modernisation of the economy transfers to the new Authority the powers of the former Competition Council and accords new powers: the Competition Authority replaces the Minister of the Economy with regards to the monitoring of merger operations. In addition, the Competition Authority is henceforth able to itself carry out investigations and possesses the possibility to decide upon recommendations in terms of competition questions and to issue recommendations to the Minister who is responsible for the sector. This aims to improve the competitive functioning of the markets.

Order No. 2008-1161, dated 13 November 2008, which modernises the regulation of competition, confers upon the Competition Authority reinforced powers.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Anti-competitive practices may take different forms. They are generally divided into two groups: cartels on the one hand; and abuse of dominant position on the other hand.

They are defined in articles L.420-1 and L.420-2 of the Commercial Code.

Article L.420-1: "*Concerted actions, agreements, express or implied cartels or coalitions are prohibited, even when through the direct or indirect intermediary of a company of a group located outside France, when they tend to:*

1) *Restrict access to the market or the free operation of market forces by other companies.*
2) *Hinder the fixing of prices through the free operation of market forces by favouring artificially their increase or their decrease.*
3) *Limit or control the production, outlets, investments or technical progress.*
4) *Share out the markets or sources of supply.*"

There are so-called "horizontal" cartels, which involve several competing firms for the same type of product or service and so-called "vertical" cartels, which are concluded between operators situated at different levels of the economic chain as, for example, between suppliers and distributors.

Article L.420-2 of the Commercial Code: "*The abusive exploitation by a company or a group of companies of a dominant position on an internal market or with regard to a substantial part of such market is prohibited in accordance with the conditions provided for in article L.420-1. Such abuse may notably consist in a refusal of sale, related sales, or sales subject to discriminatory conditions, as well in the breach of established commercial relations, for the sole reason that the partner refuses to submit to unjustified commercial conditions.*

In addition, the abusive exploitation by a company or by a group of companies of the state of financial dependency in which a client company or supplier finds itself is prohibited when such exploitation is likely to affect the functioning or the structure of the competition. Such abuse may consist in a refusal of sale, in related sales, in discriminatory practices referred to in article L.442-6 or product range agreements."

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

11.3.1 The Dispute Jurisdiction of the Authority:

When the financial players infringe competition law, the matter may be brought before the Authority, or the latter may assume jurisdiction to deal with the matter upon its own initiative. It will examine the facts and, at the end of a process where each side is heard, it will take, if necessary, all the steps necessary for the practices in question to be stopped.

At the end of the process, several decisions are possible:

- a decision of non-suit (and there is therefore no need for the process to continue);
- a rejection (on the basis that there are inadequate supporting documents);
- a pronouncement of conservatory measures (faced with an emergency situation, before a decision on the merits has been taken – in the event of a serious and immediate infringement as regards a financial sector or as regards a company);
- a financial sanction (up to 10% of the worldwide turnover of the company);
- an injunction (to cease an anti-competitive practice or to comply with competition law);
- a decision concerning non-compliance with an injunction (possibly accompanied by fines);
- an injunction against publishing (of the sanction in the media); and
- decisions accepting undertakings: an alternative to litigation, the process of undertakings enables the company which has doubts to present to the Authority undertakings which are such as to put an end to these preoccupations, and before any notification of contentions.

(http://www.autoritedelaconcurrence.fr/user/standard.php?id_rub=402&id_article=1594; "Control of anti-competitive practices".)

11.3.2 Consulting Role:

11.3.2.1 The opinions and recommendations rendered at the initiative of the Authority:

Without it being necessary for a matter to be brought before it, the Authority can render opinions upon its own initiative with regard to any questions of competition and to issue general recommendations on a market or a particular sector. The Authority will put forward its point of view each time that it considers that this is necessary.

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This possibility is crucial to the extent that it enables the Authority to exercise an advisory and warning role, well before exercising its role as a sanctioning authority.

(http://www.autoritedelaconcurrence.fr/user/standard.php?id_rub=294; "Opinions and recommendations, Consultative role").

11.3.2.2 Opinions rendered on matters brought before it:

Concerning the compulsory referral to the Authority, the Authority must be consulted when a draft legislative or regulatory text envisages regulating prices or restricting competition (articles L.410-2 and L.462-2 of the Commercial Code). The Authority renders a reasoned decision to public bodies, in which it formulates its observations on the proposed text and suggests, if necessary, alternative solutions which are more compatible with competition.

Concerning the optional referral to the Authority, the Competition Authority may be called upon to render opinions on any issue of competition upon the request of public bodies (such as the Government and Parliament), local authorities, jurisdictions, or trade union organisations, consumers or professionals.

The sectorial authorities, such as the Audiovisual High Council, the Energy Regulatory Commission and the Authority for the regulation of electronic communications and posts, can also refer matters to the Authority.

Following an examination of the competition situation of the market in question, the Competition Authority proposes any measure that is helpful as far as strengthening competition is concerned.

11.3.3 Leniency:

It should also be noted that there is a policy of leniency. Leniency is a method which enables national competition authorities to stop, or to sanction more easily, cartels, in return for a favourable treatment granted, in certain conditions, to companies which denounce the existence of cartels and which cooperate in the proceedings that are instigated with regard to such cartels (http://www.autoritedelaconcurrence.fr/user/standard.php?id_rub=292; Negotiated procedures, French leniency programme).

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

See the answer to question 11.3.

In addition, and as regards merger operations (a merger operation occurs when two companies that were formerly independent merge, when they create a common company, or when a company takes control of one of several other companies), there are thresholds of turnover which trigger the obligation to notify the operation to the Authority (article L.430-2 of the Commercial Code).

Once the operation has been notified to the Authority, the latter proceeds with an examination of the operation, within a delay which will depend upon the nature of the operation and the problems that it comes across during the course of the examination (and for further details regarding the time periods within which the Authority reaches a decision, reference should be made to articles L.430-5 and L.430-7 of the Commercial Code).

In the event that no particular competition problems are identified or if the undertakings that are presented by the parties rectify the problems that have been noted, the operation may give rise to an authorisation with or without undertakings at the end of a quick examination, called phase 1. The decision is rendered within 25 business days as from the date of receipt of a complete file of notification.

If, on the other hand, a serious infringement of competition remains at the end of this phase, the Authority commences phase 2, in order to proceed with an in-depth analysis of the operation. In particular, the Authority will examine whether the operation is such as to impede competition and notably, through the creation, or the strengthening of a dominant position or through the creation or the strengthening of a purchase power which would place the suppliers in a situation of economic dependency. The Authority also examines whether the operation is justified by gains in efficiency which compensate for prejudicial effects that may possibly be noted as far as competition is concerned.

At the end of this examination (normally 65 business days as from the commencement of phase 2), the Authority renders a collegiate decision which may either authorise the operation without any specific conditions, or authorise it subject to the provision of undertakings, or prohibit it.

The parties, as well as interested third parties, have two months within which to seek an annulment of the decision or an amendment of the decision before the Council of State.

On an exceptional basis, the Minister of the Economy may pass over the decision of the Authority, adopting a decision on the basis of reasons of public interest (http://www.autoritedelaconcurrence.fr/user/index.php).

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

As far as the distribution of gas is concerned, article 1 of the Decree-law dated 12 November 1938 relating to the nationality of public services concessionaires provides that public authorities can only grant concessions to French citizens.

This provision is still in force, even though some modifications have been enacted in order to comply with European legislation and, more precisely, with the principle according to which discrimination on grounds of nationality shall be prohibited. As such, this provision has been amended by Decree No. 70-410, dated 15 April 1970. Pursuant to articles 1 and 2 of this Decree, the condition relating to the nationality of public services concessionaires does not apply to the distribution of gas when the individuals or the companies are nationals of an EU Member State or when the company in question was set up in accordance with the laws of a Member State and has its headquarter, main establishment or registered office in the EU.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The legislation applicable to the oil and gas sector is widely influenced by community undertakings given by France. Thus, recent laws, which have provided a new legal context for the natural gas market, have been enacted in order to transpose European Directives into French law.

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From an environmental point of view (because of its impact in the gas legislation and operation), France is also, of course, influenced by its international undertakings, such as the Kyoto Protocol, as well as its European undertakings. For instance, following the Paris Agreement signed on April 2016, France has adopted a new law on hydrocarbons in order to meet its carbon neutral goal by 2050.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

13.1.1 The Settlement of Disputes by the Energy Regulatory Commission (Natural Gas Sector):

The ERC may be contacted by concerned parties (except with regards to clients that are not eligible), in the event of any dispute relating to access to transportation works, or works concerning the distribution of natural gas and to liquefied natural gas installations, or in relation to the storage of natural gas. After an examination during which the parties are duly heard and after a possible enquiry, the Commission must reach a decision within two months (this may be extended if necessary) for the resolution of a dispute. A matter may also be brought before the Commission, in parallel, for conservatory measures. The decisions of the Commission may be appealed before the Court of Appeal of Paris, which may order the suspension of execution of a sentence (http://www.cre.fr/presentation/pouvoirs#section3; Settlement of disputes).

13.1.2 The Settlement of Disputes by a Judge:

Chapter II of Book V of the New Mining Code, as implemented by the Order dated 20 January 2011, provides for the offences and penalties in mining matters. In view of the mixed character of mining legislation, certain questions fall within the jurisdiction of administrative judges, whilst others fall within the competence of civil or administrative judges.

13.1.3 The National Energy Ombudsman:

The national energy ombudsman is responsible for examining consumer complaints, recommending solutions to disputes between consumers and suppliers or DSO of energy, and taking part in campaigns to inform consumers about their rights. If the consumer (any private, non-professional or professional customer within the micro-enterprise category, i.e. fewer than 10 employees and €2M in turnover) is in dispute with his energy supplier or distributor, he or his representative (consumer association, lawyer, etc.) can appeal to the national energy ombudsman to assist him in settling the disagreement. After examining the case the ombudsman prepares a written recommendation supported by detailed arguments which will enable the dispute to be settled within two months of the case being brought before him. The field of jurisdiction of the national energy ombudsman is strictly regulated by articles L.122-1 *et seq.* of the Energy Code (http://www.energie-mediateur.fr/accueil.html).

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

France has ratified both conventions (the New York Convention in 1959 and the Washington Convention in 1965).

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

In general, there is special difficulty, as a matter of law or practice, in litigating against Government authorities or State organs before national courts. However, concerning arbitration, the question remains whether or not public entities remain prohibited from submitting their dispute to arbitration. Indeed, pursuant to article 2060 of the French Civil Code, disputes concerning public entities and public establishments cannot be referred to arbitration. This prohibition subsists in French domestic arbitration law, albeit with numerous exceptions. For instance, article 2060 provides that orders can be issued in order to authorise industrial and commercial public establishments to submit their dispute to arbitration. In addition, this prohibition does not apply in public procurements as provided in articles 247 and 361 of the new French Public Procurement Code. However, French case-law promptly distinguished between domestic and international arbitration. Indeed, French courts entitled States and public entities to submit their dispute to arbitration when the dispute in question concerns an international commercial transaction.

The issue relating to the immunity from jurisdiction of Government authorities or State organs under French law is mainly based on case-law. French courts consider that, when entering into an arbitration agreement, the State decided to waive its immunity from jurisdiction. This waiver concerns the arbitration proceeding in itself but also the proceedings in front of national courts in relation to the constitution of the arbitral tribunal or the enforcement of the arbitral award.

By contrast, it has been considered that the State's decision to enter into an arbitration agreement cannot be considered as a waiver by the State of its immunity from execution. Nonetheless, this analysis has to be nuanced when it comes to international arbitration, since the French Supreme Court considered that a State, when giving its consent for arbitration under the ICC Rules, shall be deemed to have waived its immunity from execution (decision dated 6 July 2000). This decision was based on the fact that, under the ICC Rules, the party signing an arbitration agreement commits itself to comply with the award. In this respect, the Paris Court of Appeal applied the principle established by the French Supreme Court without reference to any arbitration rules (decision dated 12 December 2001).

As a general principle, the immunity from execution does not apply to State property linked with a commercial, an economic or a private operation. However, the immunity of execution protects the State's properties connected directly with the exercise of sovereignty, unless the State decided to waive its immunity. The French Supreme Court decided in 2011 and 2013 that such waiver has to be expressed and special. Therefore, the State had to mention the goods or categories

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of goods concerned by the waiver. However, in a recent decision dated 13 May 2015, the French Supreme Court decided to depart from previous case-law. Since this decision the waiver has to be expressed and the condition of specialty is abandoned.

The draft law Sapin II (concerning transparency, the fight against corruption and the modernisation of economic life) plans to clarify the conditions of the waiver of immunity from execution but only for diplomatic properties: the waiver will have to be express and special. However, the draft law does not provide a similar rule for the other goods of foreign States. Consequently, for those goods, the decision of 13 May 2015 of the French Supreme Court will still apply: the waiver will only have to be express.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

In the past, French Courts did not hesitate to condemn governmental authorities or State organs. For instance, the French Administrative Supreme Court, in its decision dated 30 April 2014, decided to condemn the French authorities and required to proceed with a re-examination of the request for extension of an exploration permit submitted by the American company Hess Oil. The French authorities were requested to proceed with such re-examination on pain of a monetary penalty. This decision resulted from the non-compliance of the French authorities with a first decision issued by the Supreme Court on 17 July 2013, condemning the State to re-examine the request for extension submitted by the American oil company.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

As stated in section 3.1.1, France adopted a new bill in order to prevent the granting of new exploration permits.

There are no new cases in Oil & Gas Regulation Law in France. However, as regards cases in competition matters in relation to the gas market, in October 2015, Direct Energie made a referral to the *Autorité de la concurrence*. In particular, it reported that Engie's pricing practices on its market offers were liable, in its opinion, to be anti-competitive. It also requested the order of interim measures. In a decision issued on 2 May 2016, the *Autorité de la concurrence* found that, given the information in the file known to date, Engie had fixed the prices of its individual market offers, namely those that are non-catalogued and reserved for business customers, without taking the real costs into account, at the risk of establishing predatory or exclusionary pricing. Consequently, and before reaching its decisions on the merits of the case, the *Autorité* has imposed various urgent measures on Engie so that the prices of these offers are a better reflection of the reality of its costs. The decision was overturned by the Court of Appeal on 28 July 2016. The appeal's judgment was appealed before the Court of Cassation (Supreme Court). The case is pending.

(http://www.autoritedelaconcurrence.fr/user/standard.php?id_rub=630&id_article=2765.)

As regards deliberations of ERC, the Commission issued a deliberation on 15 September 2016 relating to changes in the balancing rules of gas transmission networks on 1 October 2016 (http://www.cre.fr/en/documents/deliberations/approval/balancing-rules-of-gas-transmission-networks-on-1-october-2016/read-the-deliberation) and a deliberation on 10 March 2016 forming a decision on the equalised tariff for the use of GRDF's public natural gas distribution networks (http://www.cre.fr/en/documents/deliberations/decision/grdf-s-public-natural-gas-distribution-networks/read-the-deliberation).

As regards trends:

- On 1 April 2015, a common market area, made up of the GRTgaz South and TIGF areas, is set up under the name Trading Region South (TRS) and in 2018, a unique marketplace in France will be created, after realisation of the necessary investments for the abolition of the congestions on gas networks (http://www.cre.fr/documents/consultations-publiques/creation-d-une-place-de-marche-gaz-unique-en-france-en-2018/consulter-la-note-technique).
- The energy efficiency certificates scheme was created by Law No. 2005-781 of 13 July 2005 on the programme setting energy policy guidelines ("Loi POPE"). It is based on an obligation to achieve energy savings required by the government from energy sellers. A multi-year goal is fixed and divided among operators according to their sales volume. On 1 January 2015, the scheme has entered its third period for a three-year period: the obligation amounts to 700 TWh CUMAC (accumulated and updated) for the 2015–2017 period. The Law of 17 August 2015 on the energy transition for a green growth has already planned a fourth obligation period from 2018 to 2020. People obliged for the 2015–2017 period are energy suppliers whose sales exceed a certain threshold, including:
  - Sales of domestic heating oil to households and enterprises in the service sector beyond 500 cubic metres, in the national territory.
  - Release for consumption of motor fuel beyond 7,000 cubic metres, in the national territory.
  - Release for consumption of liquefied petroleum gas as vehicle fuel beyond 7,000 tonnes, in the national territory.
  - Bulk sales of liquefied petroleum gas to households and enterprises in the service sector beyond 100 million kWh of energy gross calorific value, in the national territory.
  - Sales of natural gas to households and enterprises in the service sector beyond 400 million kWh of energy gross calorific value, in the national territory.

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After years working in the raw materials and energy sector, Thierry Lauriol joined the French international law firm Jeantet and set up the Energy & Mining department in 1993.

The firm assists clients in matters relating to the electricity, oil & gas, mining and infrastructure sectors. The team advises and assists investors in the context of studies and project development (including the negotiation and drafting of different contractual aspects of the projects) as well as national authorities with regard to the analysis of specific legal situations and reforms specific to a sector. We regularly advise major European players in the electricity sector on different aspects of their activities, such as key electricity producers in France in the context of the construction of electricity power stations. We also advise operators and financial institutions in relation to major projects in the wind farm sector in France, a rapidly expanding area. Our department has been active for many years on the African continent and, in particular, in West Africa.

The firm is part of the Energy Law Group (www.energylawgroup.eu), a network of 40+ independent law firms comprising a network of approximately 500 lawyers.

The ELG, which was founded in 1993 by Thierry Lauriol, offers to its clients leading transversal market advice across 40 jurisdictions (Europe, the Middle East, Africa and beyond). Clients include corporations, banks, State entities, regulators and institutions.

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Gabon

Project Lawyers

Jean-Pierre Bozec

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Oil overview

Gabon is a Central African country based in the famous Gulf of Guinea, located on the Atlantic side of the African continent and crossed by the equator line. Gabon became independent in 1960 and has since developed a stable and peaceful environment attracting major international investors for, in particular, oil and gas, mines, and forests, which remain the main sources of revenue for Gabon.

Gabon is among the top five oil producers in Sub-Saharan Africa, has been an oil producer for more than 50 years and had its peak oil production in 1997 when oil production reached 370,000 barrels per day. Since 1997, oil production has been declining. It is still around 200,000 barrels a day, with a total production estimated for 2016 at around 11 million tonnes. Since July 2016, Gabon has returned to OPEC membership, which the country was not part of for several years. According to OPEC's World Proven Crude Oil Reserves by country for 2016, there were a total of two billion barrels of proven offshore and onshore reserves, with most of them being located in the south west of Gabon in the Port-Gentil area. To face the natural decline of mature fields, the government has oriented its policy to the exploitation of its offshore reserves (offshore is about 70% of the entire reserves).

Gas overview

Natural gas production is not yet very important in Gabon, but, in August 2014, Eni announced a critical gas discovery in shallow water and Shell and CNOOC announced a gas discovery in a deep pre-salt reservoir offshore.

Natural gas has been used for several decades for the production of electricity in Port-Gentil. In 2008, a pipeline was put into operation between gas fields and power stations in Port Gentil and Libreville.

With the new gas discoveries, the objectives of the State are to create a master plan to determine the most relevant use of the gas potential and to promote the exploration and production of natural gas, excluding associated gas reserves. Gabon has indeed the ambition to develop the production and domestic use and export of this sustainable energy source.

Gabon's natural gas resources should be developed in order to provide natural gas not only for domestic consumption but also for the two fertiliser plants being built with a consortium of, notably, the State of Gabon and Olam as well as with the Moroccan OCP Group in the Port Gentil special economic zone.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Gabon is a relatively large country (267,670 km^2) but with a small, growing population (about 1.8 million inhabitants).

The low electricity production in Gabon is provided by fossil fuels (54.4%) and by hydroelectricity (45.1%). Solid biomass, marginally developed, provides 0.4% of the total.

The country has insufficient electricity capacity to supply the increasing demand of about 6%–8% per year.

The country has, therefore, launched a plan to increase the national power generating capacity by 1,200 MW by 2020 through the development of several dams throughout the country and natural gas and diesel power plants.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

As far as natural gas is concerned (including associated gas), it is used in power plants and reinjection in oil wells (due to a 2010 country ban on gas flaring). The industrial use of natural gas will, however, be developed in order to meet the new power plants' and fertiliser plants' needs.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Natural gas is not exported from Gabon.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

See question 1.1 for an overview of the oil and gas sector in Gabon.

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With about 30 oilfields in production, Gabon is currently the fifth largest oil producer in Africa, but production is declining. The Gabonese Government, at the end of October 2013, launched its 10th bidding round for new oil blocks leading to the signature of eight new production sharing contracts with Marathon, Petronas, Repsol, Noble and Woodside, Impact Oil & Gas and Ophir which are all working on their exploration programmes. A new code of hydrocarbons was promulgated on 28 August 2014 and a few production sharing contracts have been in negotiations since the reduction of oil prices from the end of 2014. New oil and gas discoveries have been made in 2014 by notably Perenco, Vaalco and Eni in the conventional domain, while Shell and CNOOC declared a gas discovery in deep waters offshore in October 2014. At the end of 2015, the Government launched the 11th public round to attribute five new offshore oil fields, but due to the current market situation and proposed economic terms, this round has been suspended. The Government is now working on changes on the 2014 hydrocarbons law to adapt terms to current market conditions.

In the meantime, the Gabonese oil and gas sector remains active with farm-ins and farm-outs as well as changes of control occurring in 2017: notably Shell Gabon and Shell Upstream Gabon taken over by Assala Energy (supported by Carlyle); Harvest Dussafu taken over by BW Offshore; and certain Total Gabon fields transferred to Perenco.

Major current oil operators in the upstream industry include Total Gabon, Assala Energy (formerly Shell), Perenco Oil & Gas Gabon, Addax Petroleum/Sinopec, Vaalco and Maurel & Prom.

A national oil company, *Société Nationale des Hydrocarbures du Gabon*, was established in August 2011, with the specific aim of holding and managing participations in the exploration and exploitation of blocks in coordination with the State and which became more active in the management of State participations since 2017.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Please refer to question 1.2 above.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Oil and other mineral products represent more than 70% of Gabon's general exports.

Currently, Gabon still exports more than 90% of its crude oil and the rest of its production is processed locally by the local refinery named SOGARA.

A partnership agreement has been signed in mid-2014 between the Gabon Oil Company and Samsung to build and operate a new refinery within the next few years in the special economic zone of Port-Gentil to replace the old SOGARA refinery. Negotiations of implementation agreements are still in progress.

2.4 To what extent is your jurisdiction's oil production exported?

As indicated above, Gabon exports more than 90% of its crude oil. 51% of it is exported to Asia, 31% to Europe, 15% to Latin America and 13% to North America.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

A new hydrocarbons law was promulgated in 28 August 2014 by Law no. 11/2014, notably replacing former Law no. 14/82 in the upstream industry and several laws in the downstream industry.

This Law no. 11/2014 provides for the new State approach in its relations with operators and its willingness to influence and control more oil and gas activities.

As far as upstream activities are concerned, the law proposes to operators several types of upstream contract:

- services contracts (for geological and geophysical and other studies for State promotion of the oil and gas domain);
- technical evaluation agreements (superficial appraisal and limited to 18 months);
- exploration contracts (exploration only, but preference right for PSC negotiation in the event of discovery and rights for indemnity for the contriver);
- production sharing contracts (development and production); and
- exploration and production sharing contracts (exploration, development and production),

according to a model to be approved by a Ministerial Order, which cannot, however, derogate from the hydrocarbons law. The final three types of oil contracts listed above are approved by Presidential Decree.

While a services contract was signed in September 2014 with CGG for a vast offshore multi-client programme, production sharing contracts (PSCs) remain the main model used in the upstream industry, and all blocks allocated in 2014 involved PSCs.

The main proposed PSCs terms remain:

Issues	PSC Terms
Work commitments during exploration phase	Volume, budgets and phases negotiable provided they do not exceed six years, subject to possible limited extensions
Exploitation period	10 + 5 + 5 years
State participation	20% during development and exploitation
State-owned oil company (GOC)	15% maximum at market value
Superficiary royalty	Exploration: XAF 50 per hectare Exploitation: XAF 5,000 per hectare
Cost stop	65% for conventional domains 75% for deep and ultra-deep waters
Signature bonus	Negotiable
Production bonus	Negotiable
Proportional mining royalty	Negotiable between 13% and 17%
Production sharing	Conventional: 1st tranche: 30.77% minimum for the State Deep waters: 1st tranche: 23.08% minimum for the State
Corporate tax	35% on the contractor's oil profits

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Issues	PSC Terms
Support fund(s)	Negotiable
Dismantling fund	Fund domiciled in an agreed Gabonese bank
Domestic market	15% discount on fixed price
Provision for diversified investments (PID)	1% of the turnover, 75% of which is cost recoverable
Provision for hydrocarbons investments (PIH)	2% of the turnover, 75% of which is cost recoverable

Pursuant to Decree no. 0211/PR/MPH dated 6 April 2016, access to the upstream oil sector is either by way of tender process or through direct consultation, both processes leading to the signature of hydrocarbons contracts, but subject to a strict procedure. Under Decree no. 0041/MPH/SG/DGH dated 15 January 2016, the granting of an exclusive licence for development and operation of a hydrocarbons deposit that has been declared a commercially viable discovery is subject to the prior approval, by the administration in charge of hydrocarbons, of a development plan of the said deposit. The plan is developed by the economic operator.

Law no. 11/14 provides that an independent regulatory agency be created in order to regulate and control upstream and downstream activities, but the Minister in charge of hydrocarbons remains the entry point in order to enter into Gabon oil and gas activities. The Gabon Oil Company acts as a partner with oil operators and does not currently generally manage the State's participations, which mainly remain under the Minister in charge of hydrocarbons' control.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Oil resources belong to the State. While mature oil fields operated under concession systems, formerly governed by the 1962 Mining Code, still exist until their terms elapse, all upstream oil contracts signed in Gabon after 1983 are PSCs. Once the PSC is signed, the new hydrocarbons laws provide that some petroleum titles are granted to the contractor according to the duration and conditions agreed within the PSC, subject to the new hydrocarbons law provisions.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Exclusive authorisations are granted according to the PSC terms and Law no. 11/14.

Exclusive exploration authorisations can last a maximum of six years, with different phases to be negotiated and subject to possible limited extensions, while exclusive exploitation authorisations are granted for 10 years for crude oil and 15 years for gas, which may be renewed twice only for five-year periods.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Under the new PSC terms, the State has a participation in any exploitation fields of 20%.

With the incorporation of the State-owned oil company, *Société Nationale des Hydrocarbures du Gabon* (or more commonly "Gabon Oil Company – GOC"), GOC has an option for a maximum 15% direct participation in the PSCs that it acquires at market price.

The State can, in any case, transfer its participation interests to any company it wants (public or private), but the State has also pre-emptive rights on transfer of interests.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

In addition to, notably, personal income tax (from 0–35%), wage tax (5%), social contributions on wages (22.6%) and withholding tax on services (9.5% and 10%), the contractor is required under the usual hydrocarbons law to:

- Recover all petroleum costs incurred (for the needs of petroleum operations which are not excluded from recoverability under the PSC accounting procedure), but not exceeding the percentage of net production per year as set out in the PSCs.
- Share the remaining production with the State according to tranches provided within the PSCs and the profit oil received by the contractor, now being before corporate income tax is applied.
- Pay the contributions, taxes and royalties provided for in the PSCs, and in particular:
  - Proportional mining royalties (depending on the daily production and type of fields involved) on the total available production.
  - Annual superficiary royalty (including during the exploration period) as provided by the PSC.
  - Corporate income tax at a rate of 35% of the contractor's oil profit.
- Pay the signature, extension and production bonuses according to the PSC terms.
- Pay the contributions to the funds provided within the PSCs, notably the hydrocarbons fund, the fund for State equipment, the fund for local communities and the fund for dismantling equipment.
- Pay taxes on transfer of interests and changes of control.
- Pay certain customs duties, in particular at a rate of 5% during the exploitation phase.
- Pay contributions toward training.
- Give preference to nationals in recruitment and use of local sub-contractors.
- Contribute to domestic market needs by delivering a portion of oil production to the State with a discount to the fixed price of 15%.

3.6 Are there any restrictions on the export of production?

The hydrocarbons Law no. 11/14 provides that when local needs are met, the Minister in charge of hydrocarbons can authorise exports of hydrocarbons. Therefore, and apart from the requirement to contribute to the domestic market needs and certain foreign exchange regulations, there are no other restrictions on exports of crude oil and natural gas.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Payment of current international transactions made through banks

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and supported by documents are, according to regional Economic Community of Central African States (CEMAC) foreign exchange regulations applicable in Gabon, usually free. The CEMAC legislation provides, however, that certain capital movements may be subject to declarations or authorisations. Repatriation of export proceeds is also a requirement of such CEMAC legislation, even if, after repatriation, funds can be transferred through banks quite easily for justified international transactions.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Partial or total transfers of oil interests to an assignee with good technical and financial reputation are possible under PSCs. In any case, no transfer can jeopardise the State interests, impact the performance of petroleum operations or reduce the technical and financial capabilities of the contractor.

In addition, the State holds a pre-emption right in respect of any transfer of interests.

A transfer of oil interests to a third party and shares (as opposed to transfers to affiliated companies and possible partners in the PSC, which are only subject to a declaration) is subject to prior authorisation from the Hydrocarbons Administration.

The assignor must inform the Hydrocarbons Administration in writing, setting out the name, quality and nationality of the assignee, and all the indications relating to its financial and technical capacities, its legal status, and the form and financial conditions of the proposed transfer of the oil interest.

If the administration does not raise any objection, usually within 45 days following the date of receipt of the information described above, and if the State does not exercise its pre-emption rights within the same 30 days, authorisation is usually deemed to be granted.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

A mother company guarantee is required to be provided to the State under PSC terms.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

International oil project financings are common in Gabon and past experience has demonstrated that the State may authorise a charge over shares of an oil operator, and confirmed recently that it also accepts a charge on the contractor's interests.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

A Decree dated 16 May 2011 has been adopted whereby any non-Gabonese resident person who wants to invest in the Gabonese hydrocarbons sector through the direct or indirect holding of the control of a Gabonese company, or the acquisition of the business of a company operating in Gabon, needs to obtain prior authorisation from the Minister in charge of economy. The Minister has two months to reply to such application.

As far as oil operations are concerned, environmental regulations also require, notably, specific authorisation for impact studies and classified installations, which may affect the environment.

Since the hydrocarbons Law no. 11/14, it is also worth pointing out that while oil contractors still have the choice to operate their Gabon oil and gas interests either through registration in Gabon of a branch of a foreign company or the incorporation of a local subsidiary, the duration of a branch lasts beyond the usual two-year period for the exploration phase, while the incorporation of a local subsidiary will have to be considered during the exploitation phase.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Under Gabonese legislation on classified installations, as well as the new hydrocarbons law, any operator has to decommission its equipment at the end of exploitation. In order to secure these dismantling obligations, contributions to a fund for such dismantling obligations needs to be made by the operator from the beginning of production up to a percentage of the value of the contemplated dismantling obligations, to be provided within the PSC. The contributions need to be deposited in a Gabonese bank and co-managed by the State and the operator.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The hydrocarbons Law no. 11/14 provides that construction, operation of transportation and storage of hydrocarbons facilities are subject to an authorisation granted by an Order of the Minister in charge of hydrocarbons according to a specification to be provided by regulatory measures notably under Decree no. 0201/PR/MPH dated 6 April 2016, that provides for the rules of construction and exploitation of oil and gas storage, activity of which is subject to the prior approval of the hydrocarbons administration. Storage construction and exploitation of oil and gas products are opened to any legal person that has proven their technical and financial capacity. Law no. 11/14 guarantees free access and transparent tariffs *vis-à-vis* third parties, subject however to priority and availability of facilities granted to such operators.

Tariffs have to be approved by the Minister in charge of hydrocarbons.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Under the hydrocarbons Law no. 11/14, imports and exports of hydrocarbons are now subject to a limited term authorisation when required, according to specifications to be provided by regulatory measures (not yet adopted).

Obviously, compliance to customs clearance and CEMAC foreign exchange regulations are required.

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5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Please refer to question 4.1 above, as the same rules apply.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Similar to question 3.13 above, the hydrocarbons Law no. 11/14 provides that construction, operation of transportation and storage of hydrocarbons facilities are subject to an authorisation granted by an Order of the Minister in charge of hydrocarbons according to a specification to be provided by regulatory measures, notably under the abovementioned Decree no. 0201/PR/MPH dated 6 April 2016. Decree no. 0039/MPH/SG/DGH dated 15 January 2016 also regulates conditions of transfer and repatriation of oil products to storage places. Law no. 11/14 guarantees free access and transparent tariffs *vis-à-vis* third parties, subject however to priority and availability of facilities granted to such operators.

Tariffs have to be approved by the Minister in charge of hydrocarbons.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

Please refer to question 6.1 above, subject to, notably, land and environmental authorisations which must also be obtained.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Most of the oil contracts in question (old concessions or PSCs) provide that the operator can erect all the transportation facilities it needs in accordance with the applicable law. Once the place of the transportation network is agreed between the State and the oil and gas operators, environmental impact studies and a procedure relating to classified installations which may damage the environment, as well as land issues, are considered.

The State may support such initiatives by considering the public interests met by such transportation networks and authorising operators to affect the rights of private parties on their land and/or expropriating some land if necessary, considering, however, that as Gabon is covered by 85% of forests, most of the land in question is usually State-owned land, so no critical issues exist in practice.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Transportation agreements are usually agreed between operators to share transportation and storage facilities, but thanks to the hydrocarbons Law no. 11/14, the independent regulatory agency should control applicable access and tariffs *vis-à-vis* third parties.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Due to the past few regulations applicable to upstream activities, some transportation pipelines are connected, but through agreements concluded between operators which usually also operate their own private storage and export terminals. When an issue arises in the negotiation of such interconnection agreement, the State's assistance is usually required in order to facilitate such agreements. The new independent regulatory agency provided by the hydrocarbons Law no. 11/14 should facilitate mediation between operators and users of transportation networks.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Under the hydrocarbons Law no. 11/14, use of the transportation network is subject to priority and available capacity of the operator.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

According to the hydrocarbons Law no. 11/14, tariffs are negotiated between parties, but subject to approval by the Minister in charge of hydrocarbons.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The transmission/distribution of refined and processed oil and gas products are subject to State authorisations for storage, transportation and distribution of such products.

The four main distributors of refined products are Total, Engen, Lybia Oil and Petrogabon (local), bearing in mind that the price of petrol, diesel, gasoline and gas are regulated products with fixed prices guaranteed by a public body in charge of the stabilisation of such prices. Since 2016, prices remain regulated, but are now periodically revised according to the international market price. Gas is distributed to the population by the above agreed distributors through bottles and tanks.

The hydrocarbons Law no. 11/14 also providing for downstream activities is due to be completed by regulatory measures (not adopted yet), but there is currently no real network of direct distribution of natural gas save for certain industrial uses and for upstream operations.

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7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Apart from the industrial use of certain quantities of natural gas operated and delivered by Perenco to the Gabon electricity operator, which requires State approval, there is no network of distribution by pipeline of natural gas to the population.

7.3 How is access to the natural gas distribution network organised?

This is not applicable yet.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

This is not applicable yet, but the hydrocarbons Law no. 11/14 provides that, if necessary, the State can decide to impose the use of such networks and require any operator of gas to have a minimum permanent stock.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

This is not applicable yet.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Hydrocarbons being a regulated activity, it is likely that acquisition of interest leading to the direct or indirect transfer of downstream activities will be at least subject to State authorisations (this needs to be specified in regulatory measures to come).

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Order no. 837 of 28 November 2003 lays down conditions for exporting petroleum products to the countries of the CEMAC. These conditions relate, in particular, to the quality of oil storage and to the nature of stocks for export.

In any case, under the hydrocarbons Law no. 11/14, this is subject to ministerial authorisation according to conditions to be completed by regulatory measures to come.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

As far as Gabon is concerned and apart from local consumption and industrial gas needs, only crude oil is traded on international markets for the moment.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

LNG facilities are part of a category of facilities regulated under Gabonese law. These are notably subject to authorisation granted by Presidential Decree, after, notably, compliance with the "classified facilities" specifications governed by the new 2014 Environmental Code.

However, due to the current low level of gas production in Gabon, it is too early to speak about LNG facilities, while such possibilities may be considered in the future for the development of gas fields discovered in 2014.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Any processing of hydrocarbons is subject to a Presidential Decree under the new hydrocarbons Law no. 11/14.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

This is not yet applicable.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

This is not yet applicable.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Thanks to the hydrocarbons Law no. 11/14, the downstream sector is now more organised and subject to authorisations, while regulatory measures to come are needed to complete it.

- Authorisation regime:
  - by Decree for processing of hydrocarbons;
  - by Ministerial Order for other downstream activities: transport, storage, retailing, import, export of refined product; and
  - payment of royalties.
- Specific regulations:
  - for processing of hydrocarbons: priority for domestic markets needs and for buying local crude oil and gas;
  - stabilisation mechanism for certain refined products; and
  - minimum stock required for distribution of refined products.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Apart from specific regulation relating notably to import, export, transportation and storage of oil, which are subject to ministerial authorisation, the hydrocarbons Law no. 11/14 does not yet provide for any specific regulations regarding the trading of oil. This law

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is yet to be completed, however, by regulatory measures which are soon to be published.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The regulation of competition aspects or anti-competitive practices in the oil and gas sector is not subject to a special regime, apart from the regulated price of downstream oil and gas products provided in the hydrocarbons Law no. 11/14. We suspect, however, that with the new independent regulatory agency provided by the hydrocarbons Law no. 11/14, things may change in the near future.

Pure competition issues, therefore, currently involve mainly the CEMAC regional regulations and national legislation on trust and abuse of a dominant position, rather than price. CEMAC Regulation no. 1/99/UEAC-CM-639, modified by Regulation no. 12/05, deals with anti-competitive practices. It provides for the existence of a Regional Competition Council, responsible for advising the Executive Secretary of CEMAC on all questions or disputes regarding competition.

The 1989 domestic competition law lays down the rules of competition in the Gabonese Republic and provides for the establishment of a Competition Commission under the authority of the Minister in charge of economy.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

To determine whether conduct is anti-competitive, the CEMAC Regulations mentioned above provide that any practice liable to impede the free play of competition, notably cartels, abuse of dominance, and mergers which substantially lessen competition, are prohibited. All agreements between companies, any decisions by company associations and concerted practices which may affect trade between CEMAC Member States and which have as their effect the restricting or distorting of competition are also prohibited. This may involve or relate to, notably, the limiting or control of production, markets, technical developments or investments, market shares or sources of supply, or the application, in respect of trading partners, of dissimilar conditions for equivalent services, placing them at a competitive disadvantage, and a concentration on the conditions of a submission for bidding for a share of the market, to the detriment of other competitors.

To determine whether a trust is prohibited, the CEMAC Regulations mentioned above state that practices which significantly restrict the choices of suppliers and/or users restrict access to supplies or markets, or create barriers to entry, particularly by prohibiting distributors from parallel imports, are incompatible with the common market concentrations.

Finally, any monopoly or any situation likely to promote the acquisition of a market share greater than or equal to 30% constitutes a dominant position. Abusing a dominant position within the common market or in a part thereof is prohibited if trade between CEMAC Member States is likely to be affected.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

CEMAC antitrust authorities, as well as national authorities, can take actions in order to avoid certain practices. The range of actions varies from control with penalties, to prohibitions of certain actions with penalties computed on an amount of turnover depending on the facts in question.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

According to the abovementioned antitrust regulations, CEMAC antitrust authorities can indeed refuse to authorise a merger. The said CEMAC antitrust regulations are being updated in order to grant such authorities with more and clear powers.

In addition to such CEMAC Regulations, we also note that, as far as hydrocarbons activities are concerned, any change of control of an oil contractor is subject to the Minister of Oil's authorisation, while if it is for the benefit of a foreign investor, the Minister in charge of economy must also grant his authorisation according to the Decree of 16 May 2011.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

As indicated above, the Decree dated 16 May 2011 has been adopted, whereby any non-Gabonese resident person who wants to invest in the Gabonese hydrocarbons sector through the direct or indirect holding of the control of a Gabonese company or the acquisition of the business of a company operating in Gabon needs to obtain prior authorisation from the Minister in charge of the economy. The Minister has two months to reply to such application and we never experience any issue with this.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

In August 2014, Gabon adopted a code for sustainable development and a new environmental code. Any issues relating to international treaties regarding the environment are taken into account and already provide for, for instance, the gas flaring prohibition and the requirement to repatriate funds for dismantling obligations.

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13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Under PSC terms relating to upstream activities, any dispute between parties shall usually be settled through International Chamber of Commerce (ICC) arbitration or, in some cases, the OHADA court for arbitration as well, the seat of which is in Abidjan (Ivory Coast). In other downstream and midstream sectors, local courts will be competent for any dispute, except otherwise agreed by the parties, in particular when negotiating major projects like refinery or fertiliser plants.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Gabon ratified the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, as well as the ICSID treaty and the OHADA treaty for the harmonisation of business laws (including arbitration laws) in 17 Sub-Saharan countries.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

While the State usually refuses to waive its rights for immunity of execution on its assets, past experience demonstrates that Gabon complies with international arbitration awards, subject to compliance with the domestic enforcement procedure of foreign decisions and awards.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

The State of Gabon has been recognised as right or liable in some local, as well as international, arbitration decisions. Such decisions, as far as the oil industry is concerned, remain, however, confidential.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

A new hydrocarbons law was promulgated in August 2014, but most of the necessary implementation measures are still needed to complete it, in particular as far as downstream activities are concerned.

Cards between upstream Gabonese oil producers are being reorganised since 2016 with the change of control of Maurel & Prom in 2016 for the benefit of Pertamina, the similar transaction in 2017 for Shell Gabon (which remains one of the main oil producers and crude oil export terminal operators in Gabon) and Shell Upstream Gabon for the benefit of Assala Energy, and five Total Gabon fields producing about 13,000 b/d transferred in 2017 to Perenco.

Hopefully, the announced reform of the hydrocarbons Law no. 11/14 will meet the international oil and gas companies' appetite for the Gabon basin.

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Jean-Pierre has wide experience of projects and project financing throughout North, West and Central Africa, in particular as far as energy and mineral resources are concerned. Over the course of his career, he has developed a strong expertise in negotiation and drafting State contracts (production sharing contracts, establishment convention, mining conventions, BOT and concession agreements), in legal and tax structuring of projects in Africa, in particular for oil and gas, utilities, transportation infrastructures and mines. He graduated from Exeter University (UK) with an LL.M. in international business transactions and from Rennes University (France) with a postgraduate degree in business law.

The leading experience of Jean-Pierre Bozec in Gabon has been consistently recognised by *Chambers Global*, *The World's Leading Lawyers*, *The International Who's Who of Energy Lawyers 2017* and others.

PROJECT LAWYERS

Project Lawyers is an independent successful Gabonese law firm, established by Jean-Pierre Bozec, after several years as managing partner of a Gabon international law firm he developed.

Project Lawyers' team is committed to providing high-quality and innovative legal services to major corporations, financial institutions and international law firms, especially in the energy and mineral resources project and project financing sectors.

Project Lawyers has been consistently selected as a leading law firm by *Chambers & Partners*, by Corporate INTL, *Who's Who of Energy Lawyers*, as well as Gabon law business firm by *Global Experts*, *IFLR 1000 Energy and Infrastructure Sub-Saharan Africa* and others.

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Greece

KLC Law Firm

Dr. Vassilis Karagiannis

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In Greece, all demand is exclusively met by imports. The National Gas Transmission System (NGTS) has three main entrances: Sidirokastro (on the Greek-Bulgarian borders); Kipoi (on the Greek-Turkish borders); and Agia Triada, where regasified LNG from the regasification terminal of Revithoussa enters the NGTS. A new pipeline which crosses Greece and Albania, the Trans Adriatic Pipeline, known as the TAP, is under construction. The TAP is aimed at transporting Azeri gas to Italy and further to Western Europe by crossing Greece and Albania.

The NGTS is operated by DESFA, a fully owned subsidiary of DEPA and the incumbent gas operator in Greece. DESFA currently, for the moment, operates under the IPTO model, but its privatisation is currently in progress. Should this process be completed, DESFA will then operate under the Full Ownership Unbundling Model (FOU).

Recently, the law provided for the unbundling of the distribution networks. Thus, Greece has four distribution network operators, the so-called "EDAs" in the regions of Attica, Thessaly and Thessaloniki, respectively, and the operator for the rest of Greece, the so-called "DEDA".

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

The share of natural gas in the country's total primary energy supply (TPES) increased to 13.82% in 2013. Because of the growth in the demand for electricity and the subsequent construction of new gas-fired power stations, demand for natural gas steadily increased and in 2012 stood at 4.4 bcm (12 million m^3/d). The forecast for 2018 is approximately 4.9 bcm. Oil represents approximately 45% of the country's TPES (317.9 kb/d). A sharp decline to around 274.6 kb/d is forecast for 2018.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

The requirements are met exclusively by imports.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

There is no significant gas export activity in Greece.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Almost all of the crude oil used in Greece is imported. Domestic production of oil is limited to the Prinos offshore field in the Kavala Gulf in the northern Aegean Sea. There are two companies refining oil in Greece: Hellenic Petroleum S.A.; and Motor Oil Hellas. The four refineries in Greece have a total crude distillation capacity of around 490 kb/d. Around two-thirds of this capacity is owned by Hellenic Petroleum S.A., with two refineries located in the Athens area and a third near Thessaloniki. The fourth refinery, owned by Motor Oil Hellas, is located in Corinth. There are 10 oil terminals in Greece, seven located in the Attica area (Athens) and the remaining three in the Thessaloniki area. Six oil terminals receive crude oil; four of these terminals are located near the refineries. In the downstream market, over 20 trade fuel companies operate in Greece, with six of them covering almost 70% of inland consumption.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

As already mentioned, oil is the dominant energy source in Greece representing approximately 45% of the country's TPES.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Only a small portion of the oil demand in Greece is covered by domestic production (currently, some 5 kb/d).

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2.4 To what extent is your jurisdiction's oil production exported?

The country's small amount of oil production is domestically consumed. However, Greece was a net exporter of refined oil products in 2012, exporting 245 kb/d of such products. The destination of oil exports was mainly Turkey (22%), Singapore (9%), Lebanon (7%) and Libya (7%).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Law 2289/1995 (GG A 27/1995), transposing EC Directive 94/22 (OJ L 164 of 30.06.1994, p. 3), as amended by Law 4001/2011 (GG A 179/2011), is the main applicable legal framework for the prospection, exploration and production of hydrocarbons in Greece. According to the said Law, all rights of prospection, research and exploration of hydrocarbons in onshore and offshore areas within the sovereignty of Greece belong to the Greek State. The management of these rights are vested to a fully state-owned company named "Hellenic Hydrocarbon Resources Management S.A." – HHRM (see also Presidential Decree 14/2012). The HHRM is, *inter alia*, responsible for the organisation of the exploration and production tenders for the evaluation of the offers submitted and the monitoring of the respective contracts.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

According to Law 2289/1995, as in force, the Greek State's exploration and production rights may be granted either under a Lease Agreement or a Production Sharing Agreement. Both types of agreement are signed by the Contractor and the Greek State or the HHRM, as the case may be, and approved by the Minister of Environment & Energy. Without this approval the contract is null and void.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Law 2289/1995 distinguishes two phases in the hydrocarbons upstream market. The exploration phase and the production phase. The maximum duration for the exploration phase in onshore areas is seven years and in offshore areas eight years from the date of execution of the respective agreement with the Greek State (article 5 paragraph 1 of Law 2289/1995, as in force). A possibility for an extension is provided under strict conditions. This extension cannot exceed half of the initial duration. The production phase has a maximal duration of 25 years from the date on which the Contractor notifies to the Greek State that it has discovered a commercially exploitable deposit (article 5 paragraph 8 of Law 2289/1995, as in force). This term is twice extendable for a period of five years each. The right to prospect a specific area is granted by the HHRM and approved by the Minister of Environment & Energy and has a maximum duration of 18 months.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

The law provides the contracting authority with the choice between a Lease Agreement and a Production Sharing Agreement. Under the second type of contract the Greek State will acquire ownership of a specified percentage of the extracted hydrocarbons at the moment of their extraction. Which type of agreement will be preferred for each contract area is determined by a decision of the Minister of Environment & Energy. As a matter of policy, to date, the type of Lease Agreement was the preferred type of contract.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

In the case of a Lease Agreement, the Greek State will derive oil and natural gas development value from royalties. The invitation to tender may also provide for the payment by the successful tenderer during the exploration and production phase of an annual fee corresponding to the surface of the area used for the exploration and production phase (the so-called "surface fee").

According to articles 8 and 9 of Law 2289/1995, the Lessee or the Contractor is subject to a national and regional income tax of 20% and 5% respectively, which are derived from the contract. The Contractor is exempted from any other taxation save for VAT.

3.6 Are there any restrictions on the export of production?

The Contractor is free to export the extracted hydrocarbons, unless specified otherwise in the contract with the Greek State.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Basically, as Greece is a member of the Eurozone, no such restrictions should apply. Article 2 paragraph 4 of Presidential Decree 127/1996 provides that the Contractor has the right to transfer its income abroad. However, after 28.06.2015 and the liquidity crisis of the Greek banking system, a capital control regime applies which affects the possibility of exporting funds abroad (Legislative Act of 18.07.2015 (GG A 84/2015) as ratified by article 4 of Law 4350/2015, and several times amended). Thus, transferring funds abroad is prohibited unless subject to specific limited exceptions. Said exceptions are in principle established with regard to "new money" and business transactions of legal persons. Further to that, wire transfers may be allowed on an *ad hoc* basis (subject to the approval of a special committee).

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3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

As provided by article 7 paragraph 4 of Law 2289/1995, as in force, the rights of the Lessee or the Contractor may be wholly or partially transferred to a third person, upon written consent of the Lessor and approval of the Minister of Environment & Energy. The Lessor can subject its consent to any conditions for the safeguard of its proper interests.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

According to article 2 paragraph 5 of Law 2289/1995, as in force, the call for tender for the granting of the licence to prospect a given area, issued by the HHRM and approved by the Minister of Environment & Energy, specifies the amount of the good performance letter of guarantee that the licensee should provide. This letter of guarantee must be issued from a credit institution established within the EU.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Without prejudice to the aforementioned limits in response to question 3.8, there are no other applicable restrictions in pledging the rights to develop hydrocarbons.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

As per the dispositions of Law 4014/2011, environmental licensing is requested for any activity or construction which has an impact on the environment. Presently, the applicable category of activities related to the exploration and extraction of oil and natural gas falls within Category no. 7 of Group no. 5 classified in Annex V of Ministerial Decision no. 1958/2012 (GG B 21/13.01.2012), as in force.

Such licensing incorporates, among others, clearance from the competent authorities of the Ministry of Culture in terms of legislation for the protection of cultural heritage, i.e. Law 3028/2002, as well as from the Forest Authorities in terms of suitability from the scope of forest areas' protection, i.e. Law 998/1979, as in force.

A working permit is also issued regarding the construction of auxiliary infrastructure as per the dispositions of Law 4495/2017.

Moreover, an installation permit and, following that, an operation permit must be held before the construction of oil or natural gas pumping, storage and auxiliary infrastructure, which are granted by means of a Ministerial Decision issued by the Minister of Environment & Energy as per the dispositions of article 17 of Law 3982/2011, as derived from Joint Ministerial Decision no. 2219/146/Φ15/29.02.2012 (GG 584 B/2012).

Provided that natural gas and specific oil products fall within the category of "named substances" of Directive 2012/18/EU (Sevezo III), the relevant establishments are regulated by the dispositions of Joint Ministerial Decision no. 17205/11.02.2016 (GG B 354/2016) upon which Directive 2012/18/EU has transposed into national legislation the relevant establishments which should comply with the dispositions thereof.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

According to article 5 paragraph 6 of Law 2289/1995, as in force, the Contractor can withdraw from its right to prospect a specific area. In this case it might be obliged to provide the Licensor with a lump sum. Furthermore, pursuant to article 5 paragraph 14 of Law 2289/1995, as in force, the Lessee or the Contractor can withdraw from its right to explore in a specific area or areas. In this case the Lessor has no obligation to pay the Lessee or the Contractor any damages or expenses. Generally, after the end of the prospect/exploration/production phase, the use of the land corresponding to the area under the contract must return to the Greek State free of any encumbrances. The Law and the contract provide for the fate of immovables and movables within the conceded area. Before that, the Lessee or the Contractor has the obligation to remove any mortgage or pledge. Upon the end of the production phase the Contractor must appropriately plug all producing wells and known water zones, remove all installations and restore the environment. The performance of these obligations is supervised by a special committee. The same conditions are *mutatis mutandis* applicable if the Contractor is declared forfeited or if the Contractor renounces its production rights.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

Gas storage facilities are subject to an installation permit and an operation permit according to the general rules laid down by Law 3982/2011 (GG A 143/2011). Additional environmental and urban planning requirements and authorisations may apply depending on the location of the facility.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Imports into Greece and exports from Greece of gas are not subject to holding any prior authorisation/licence. However, whoever wants to import/export gas has to book/dispose of the relevant capacity rights on the interconnections of the NGTS. Capacity rights are allocated through auctions for the entry points of the NGTS. Furthermore, DESFA must provide third-party access to the LNG terminal of Revithoussa.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Generally, no prior authorisation is required for importing/exporting

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oil products. However, a reseller who wishes to be supplied oil directly from refineries or imports has to be vested with a specific prior authorisation according to article 13 of the Licence Regulation (GG B 1036/2005).

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Greece has two oil pipelines. The first, a 220 km-long, 16-inch crude pipeline with a capacity of 50 kb/d, links the Thessaloniki port in Greece with the Octa refinery in the Former Yugoslav Republic of Macedonia (FYROM). It is owned and operated by the company Hellenic Petroleum S.A. The second, a 53 km-long, 10-inch Jet A-1 pipeline with a capacity of 42 kb/d, connects the Aspropyrgos refinery with Athens International Airport. This pipeline is owned and operated by the "Company of the fuel pipeline of Athens International Airport S.A.", a joint venture between Hellenic Petroleum S.A., Motor Oil Hellas and Athens International Airport S.A. According to article 25 paragraph 3 of Law 3054/2002 (GG A 230/2002), the owner of this pipeline is obliged to grant access to the prospective Users of the pipeline.

Regarding gas transportation, in Greece there are actually no independent pipelines, except the NGTS. Note also that the LNG terminal located in Revithoussa is part of the NGTS. Furthermore, Law 4001/2011 provides for the possibility to operate, under a licence granted by the Regulatory Energy Authority (RAE), an independent system of natural gas (the so-called "*Anexartito Systima Fysikou Aeriou*" – ASFA). Basically, in the operation licence of the ASFA, specific third-party access obligations can be imposed on the owner. However, article 76 of Law 4001/2011 provides for special conditions under which a derogation from such obligations may be granted.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

Pursuant to article 8 of Law 3054/2002, whoever wishes to transport crude oil or oil products needs to obtain an authorisation of transport by pipeline. This special authorisation is not required if the pipeline is an operational part of a refinery or links a refinery with trading installations. For constructing a pipeline, one must obtain an installation and operation permit pursuant to the provisions of Law 2516/1997 (GG A 159/1997). As already mentioned, in Greece there are no gas pipelines outside the NGTS. Such pipelines should be licensed by the RAE as ASFA. The competence of forming an opinion for the issuance of decisions regarding the definition of the installation and route of oil and natural gas pipelines and exploitation of hydrocarbons has been assigned to the Directorate of Hydrocarbons, Department of Installations of the Ministry of Environment and Energy, according to article 44 of its Internal Regulation (Presidential Decree 132/2017 (GG A 160/2017)).

Environmental licensing is necessary before the construction of oil and natural gas pipelines as per the dispositions of Law 4014/2011, as in force, and those of Ministerial Decision 1958/2012 (GG B 21/2012), as in force.

A working permit is also issued regarding the construction of auxiliary infrastructure as per the dispositions of Law 4495/2017.

Moreover, an installation permit and, following that, an operation permit, must be held before the construction of an oil or natural gas pipeline and their auxiliary infrastructure, which are granted by means of a Ministerial Decision issued by the Minister of Environment & Energy as per the dispositions of article 17 of Law 3982/2011, as derived from Joint Ministerial Decision no. 2219/146/Φ15/29.02.2012 (GG 584 B/2012).

Provided that natural gas and specific oil products fall within the category of "named substances" of Directive 2012/18/EU (Sevezo III), the relevant establishments are regulated by the dispositions of Joint Ministerial Decision no. 17205/11.02.2016 (GG B 354/2016) upon which Directive 2012/18/EU has transposed into national legislation the relevant establishments which should comply with the dispositions thereof.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Land acquisition for such purposes is regulated by article 1 of Law 367/1976 (GG A 162/1976), as in force. More specifically, the said article provides that compulsory expropriation of plots lying within urban or rural areas or the creation of rights *in rem* on such plots is permitted in favour of the Hellenic Republic or Hellenic Petroleum S.A. (formerly Public Petroleum Corporation S.A.), provided that those plots are necessary for research works, drillings, installations, exploitation and other works for hydrocarbons reserves located within Greek territory and the regions referred to in article 148 paragraph 1 of the Mining Code (Legislative Decree 210/1973 (GG A 77/1973)), i.e. reserves located beneath lakes or seas, the installation of oil production entities and storage tanks for national and foreign hydrocarbons or products/processing, including refining – said hydrocarbons and plots must be absolutely necessary for the servicing of the aforementioned installations, and as such are characterised as of public utility. Compulsory expropriation of plots lying within urban or rural areas or the creation of rights *in rem* on such plots are permitted in favour of Hellenic Petroleum S.A. (formerly Public Petroleum Corporation S.A.), a subsidiary company thereof, or municipal company for natural gas, in case these actions are necessary for natural gas pipeline routes or other gas fuels and for installations related to the system of transmission, distribution, processing and storage of natural gas and other gas fuels. These actions are characterised as of public utility. The aforementioned expropriation, regulated by the dispositions of Legislative Decree 797/1971 on compulsory expropriations, is declared by a Joint Ministerial Decision of the Finance Minister and Industry Minister.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

In the oil sector, pursuant to article 10 paragraphs 3 and 4 of Law 3054/2002, access to pipelines is granted on the basis of ordinary commercial negotiations between the owner of the pipeline and the refineries or the traders. However, the said Law provides that the owner of the pipeline in granting such access must not favour its own shareholders and apply cost-oriented prices. Similarly, access to storage facilities (article 10 paragraph 2 of Law 3054/2002) is subject to free negotiation between the interested parties respecting the principle of fair competition and the price being cost-oriented. In the gas sector, any pipeline outside the NGTS would be licensed as ASFA. Such licence could impose on the owner of the pipeline (of the system) third-party access obligations. The storage LNG facility of Revithoussa is part of the NGTS and thus regulated access conditions apply.

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6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

In the oil sector, as there are no interconnected pipelines in Greece, such question is not dealt with by national law. In the gas sector, the owner of an independent gas system (ASFA), pursuant to article 79 of Law 4001/2011, submits an application to the RAE and the RAE approves the Code of Management of the system, which provides, *inter alia*, for the applicable conditions as per interconnection with the NGTS or other systems and the necessary cooperation between the respective operators.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

See the answer to question 6.4.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

As already mentioned, the terms of the transportation of oil are basically the result of free commercial negotiations. Prices are not strictly speaking regulated. However, applicable tariffs must generally respect the principles of non-discrimination and fair competition. The tariffs for the use of the NGTS are regulated (see MD 4955/2006 (GG B 360/2006), several times amended).

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The NGTS is owned and independently managed by DESFA according to the IPTO model. According to article 63 B of Law 4001/2011, as in force, DESFA is vested with all the necessary human and financial resources for operating the NGTS efficiently. As the NGTS's operator, DESFA, acts in a non-discriminatory manner towards all Users and is fully independent from the Public Gas Corporation (DEPA), the Code of the NGTS (GG B 379/2010) regulates access conditions to the system.

The local distribution networks (Attica/Thessaly/Thessaloniki) are owned by DEPA, but independently managed by the EDAs pursuant to article 80 of Law 4001/2011, as amended by Law 4336/2015 (GG A 94/2015). Similarly, the distribution networks of the rest of Greece are owned by DEPA, but managed independently by DEDA.

The main governmental initiative pursuant to the memorandum of understanding between Greece and its creditors was the unbundling of the distribution activity from the supply activity (see Law 4336/2015, *op.cit.*).

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Pursuant to article 80 paragraphs 1 and 2 of Law 4001/2011, as in force, a distribution network operator must be granted a Licence of Distribution and a Licence of Management of a Distribution Network, which are both issued by the RAE. It is possible on the basis of the criteria of economic efficiency that the Licence of Management is granted to a third person and not the holder of the Distribution Licence. No environmental licensing is required for the operation of the natural gas distribution network in urban areas. Conversely, gas fuel pipelines and their auxiliary infrastructure are licensed as per MD 1958/2012, under specific conditions of length or pressure, if they are located beyond the road network.

7.3 How is access to the natural gas distribution network organised?

The distribution network operator must grant access to the network to all (prospective) Users in an objective and non-discriminatory manner. The specific rules of access are further established in the Licence of Management and the Code of Management of Distribution Networks (RAE's Decision 589/2016 (GG B 487/2017)).

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Every year each distribution network operator submits to the RAE its Five-year Development Plan, which is approved by the RAE and must be executed. However, the network operator can expand its network in order to accommodate new customers, even if the required expansion is not included in the Development Plan.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The fees for access and use (the so-called "basic activity") of the distribution networks are defined in the Code of Tariffs (RAE's Decision 339/2016 (GG B 3181/2016)).

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Such modifications of a distribution network must be approved by the RAE.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

There are no ownership restrictions for trading gas in Greece. However, whoever wishes to supply gas to eligible customers needs to obtain a Supply Licence pursuant to article 81 paragraph 1 of Law 4001/2011, as in force. The Supply Licence is granted by the

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RAE according to the Licence Regulation (Decision of the Energy & Environment Minister (GG B 464/2010)).

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

All natural gas commodities can be traded in Greece. Pursuant to the unbundling introduced by Law 4336/2015, offering bundled products is no longer permitted, i.e. the natural gas commodity and the distribution thereof.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

The only LNG terminal operating in the country, the terminal of Revithoussa, is operated by DESFA as part of the NGTS.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

An LNG facility will have to be authorised (licensed) by the RAE as an ASFA.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

In Greece, there is no *ex ante* regulation of the prices of LNG. The terms of service and the prices for the use of an ASFA are regulated by the Code of Management, provided in article 79 of Law 4001/2011, and the licence itself, as provided by article 74 of Law 4001/2011, as in force.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

The licence and the Code of Management of ASFA provide for specific obligations of the owner/operator to grant equal access to all (prospective) Users of the facility.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Refinery activity is normally subject to prior authorisation according to article 5 of Law 3054/2002. The owners of such licence can only supply oil products to: the owners of a trade licence; the army; large customers; cooperatives; and the owners of a retail trade licence, under specific conditions. However, it is worth noting that, according to article 23 paragraph 1 of Law 3054/2002, the refinery companies (practically all the existing refinery companies) operating at the time of its entry into force were granted an *ex lege* licence. In Greece, according to article 12 of Law 3054/2002, whoever imports crude oil or oil products to refineries, traders or large customers has the obligation to contribute to the maintenance of the obligatory emergency stock. The level of this stock is fixed to 90 days of the average net imports.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

There are no specific restrictions as per the ownership status of trade companies. Traders must be authorised according to article 6 of Law 3054/2002 and the Code of Licences. They must have legal personality and they can sell oil products to other traders, retailers, large customers or customers possessing storage facilities, under non-discriminatory and transparent terms, respecting environmental standards and safety. The following categories of licences are available: Category A – trading of crude oil and oil products; Category B.1 – trading of tax-free fuels for vessels; Category B.2 – trading of tax-free fuels for aeroplanes; Category C – trading of Liquefied Gases (LG); and Category D – trading of asphalt.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The Hellenic Competition Commission (HCC) has full jurisdiction to apply competition rules (articles 101 and 102 of the TFEU and the domestic Law of Free Competition – Law 3959/2011 (GG A 93/2011), as in force, in the oil and gas sector.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The HCC applies the traditional criteria for determining whether a collusion or unilateral practice is anti-competitive: cartels (e.g. price fixing) are *per se* prohibited, and other types of agreements (e.g. vertical agreements, long-term upstream contracts, whether supply contracts or capacity contracts) must be assessed on the basis of their effects on the market. Abuses of dominance refer to exclusionary practices (foreclosure of competitors, e.g. fidelity rebates) or exploitative abuses (e.g. excessive pricing).

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

According to Law 3959/2011, the HCC has a full range of measures against infringers of competition law. It can order the infringer to put an end to the anti-competitive behaviour and/or impose an administrative fine or order structural measures against the infringer. It can also accept commitments aiming to end the infringement on behalf of the undertakings that have violated competition rules.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

According to articles 5 to 10 of Law 3959/2011, the HCC has full jurisdiction to review mergers and concentrations, generally, in the

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oil and gas sector. According to the established EU practice and jurisprudence, in assessing concentrations the HCC refers to the so-called SIEC test ("significant impediment of efficient competition"). If the global worldwide turnover of the participating companies exceeds €150,000,000 and at least two of the participating companies realise, separately, turnovers in Greece of more than €15,000,000 each, the concentration is subject to obligatory prior notification to the HCC. Following the notification, the HCC can decide that the operation is not a notifiable concentration or does not raise serious doubts as per its compatibility with competition rules and, thus, allow the parties to proceed within one month from the filing of the notification. If the HCC estimates that the concentration raises serious doubts as per its compatibility, it will open the formal investigation procedure, which can last up to six months from the filing of the notification. The HCC can approve the notified transaction or disapprove it. It can also subject its approval to conditions in order to assure the compliance of the participating undertakings to the commitments they have proposed during the procedure.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

Basically, the acquisition of interests in the gas sector is not subject to any special prerequisites. However, according to article 11 of Directive 2009/73/EC (OJ L 211/94 of 14.8.2009) and article 65 of Law 4001/2011, a special certification procedure is applied in case a third (outside of the EU) country undertaking acquires control of a Transmission System in Greece, as in all EU Member States.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The main influence derives from the quality of the country as an EU Member State and secondary sectoral EU legislation: in the oil sector, the main law concerning the upstream production of oil, Law 2289/1995, as amended by Law 4001/2011, transposed the EC Directive 94/22/EC. In the gas sector, Law 4001/2011 transposed into Greek legal order the requirements of the so-called European third package (Directive 2009/73/EC).

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

In the upstream hydrocarbons sector, according to article 10 paragraph 13 of Law 2289/1995, as amended by article 162 paragraph 5 of Law 4001/2011, any dispute arising from the application of the Law shall be settled by an arbitral court according to Law 2735/1999 or any other recognised system of international arbitration such as the International Chamber of Commerce (ICC), the London Court of International Arbitration or the Arbitration Institute of the Stockholm Chamber of Commerce. In the gas downstream sector, article 37 of Law 4001/2011 introduced an arbitration procedure organised under the auspices of the RAE for disputes between energy companies and between energy companies and eligible customers. The deferral to this arbitration proceeding is subject to the written consent of the disputing parties. Furthermore, the Code of the NGTS contains special provisions for the amical settlement and the deferral to an expert of the disputes arising between Users and the Manager of the NGTS, which require the prior consent of the parties. If the dispute pertains, the parties may defer the case to an arbitration according to the Civil Procedure Code.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Greece is a signatory of the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and duly ratified said Convention (Law 4220/1961 (GG A 173/1961)). Greece is also a signatory of the ICSID Convention. The Convention has been ratified by Compulsory Law 608/1968 (GG A 263/1968). Greece deposited its ratification instrument on 21.04.1969. The Convention entered into force for Greece on 21.05.1969.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

The execution of judicial judgments or arbitral awards is possible against the Hellenic Republic for the assertion of financial claims, as per article 4 paragraph 1 of Law 3068/2002. The privilege of the Hellenic Republic lies on the fact that the public property of the Greek State may not be confiscated or otherwise be the basis for the execution of court decisions, as it is deemed to serve the purposes of public interest.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

There are no cases to report.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Two interventions of the HCC in the energy sector contributed significantly to the effort to liberalise the market:

In the oil downstream market, the HCC, by its Decision 602/2015, accepted the commitments of the main trading companies and

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cleared the long-term downstream contracts they had with the service stations' operators by imposing corresponding amendments of the terms of the contracts. This decision contributed to the legal certainty and the efficient operation of the downstream oil markets to the benefit of the final consumers.

In the gas sector, with several decisions (Decision 551/VII/2012, Decision 589/2014, Decision 596/2014, Decision 618/2015 and Decision 631/2016), the HCC obliged, *inter alia*, the incumbent operator (Public Gas Corporation – DEPA) to supply specific quantities of gas to the wholesale market via yearly and trimestral auctions. The HCC monitors the conditions of these auctions, contributing importantly to creating a more competitive wholesale market in Greece.

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Greenland

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In terms of oil and gas, the Greenland subsoil is considered prolific, and exploration has been carried out both onshore and offshore. However, operating conditions are severe, and the size of both the onshore and offshore territory is very substantial. The oil and gas province of Greenland must therefore be considered a frontier and a highly under-explored area. There is no natural gas production in Greenland, and as of October 2017 no commercial discovery of hydrocarbons has yet been made in Greenland. However, the resource potential of hydrocarbons in offshore Greenland remains large. The U.S. Geological Survey (USGS) in 2008 published an appraisal of hydrocarbon resources in the Arctic, in which 25 oil and gas provinces in the Arctic were quantitatively assessed. More than 70% of the mean undiscovered oil resources were estimated to occur in five provinces, two of which are related to Greenland, namely the East Greenland Rift Basin with 31,387 million barrels of oil equivalent (MMBOE) and the West Greenland-East Canada Basin with 17,063 MMBOE. So, in terms of resources and reserves, the Greenlandic oil and gas sector must be of interest to a number of IOCs and independents, provided the climatic and logistical challenges of Arctic operations can be overcome.

During the most recent drilling campaign in 2010–2011, seven offshore wells were drilled, and it may be expected that drilling will recommence under existing licences provided market conditions improve markedly. In addition, new licensing rounds for 2014–2018 were announced in September 2014 for both onshore and offshore areas and under both open door procedures and tendering rounds. The first licences hereunder have been awarded for the Jameson Land territory in an open door licence procedure in 2015. The years 2010–2011 were so far the years with the highest levels of exploration activity, with an exploration spend of approximately USD 600 million.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

There is no natural gas production in Greenland, and natural gas or LNG are currently not a large component of Greenland's energy mix. Of the electricity production, hydropower accounts for more than 70% with the rest coming from diesel-driven electricity plants. Heating is through district heating, partly supplied with diesel and hydropower (electricity heating). The vast majority of Greenland's energy consumption is covered by imported oil products.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

There is currently no natural gas production in Greenland; all needs for natural gas are covered by foreign imports.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

There is no natural gas production in Greenland and hence no exports.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

For a review of the Greenland oil and gas sector, please see question 1.1 above.

As stated, there is currently no production of oil in Greenland, and as of 2016 no commercial discovery of hydrocarbons has been made in Greenland. However, the resource potential of hydrocarbons in offshore Greenland remains large. As stated under question 1.1 above, the USGS in 2008 published an appraisal of hydrocarbon resources in the Arctic, in which 25 oil and gas provinces in the Arctic were quantitatively assessed. More than 70% of the mean undiscovered oil resources were estimated to occur in five provinces, two of which are related to Greenland, namely the East Greenland Rift Basin with 31,387 MMBOE and the West Greenland-East Canada Basin with 17,063 MMBOE. A substantial part hereof is considered to be oil. As mentioned in question 1.1 above, in the autumn of 2014, new oil and gas licensing rounds were announced for 2014–2018.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

The majority of Greenland's energy needs are met through either imported fossil fuels (oils, diesel), which account for the majority of energy requirements, or hydropower.

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2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

There is currently no production of oil in Greenland and hence domestic oil production is not a part of Greenland's energy mix.

2.4 To what extent is your jurisdiction's oil production exported?

There is currently no production of oil in Greenland and hence no export of oil.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The Greenlandic system is not principally different from similar oil and gas regulatory regimes, such as those in the North Sea area, although in a number of areas the particular conditions of operating in an Arctic environment has meant that unique regulations have had to be put in place. These specific requirements include a considerable degree of public involvement prior to the authorities' approval of concrete activities and a focus by the authorities on protection of the fragile Arctic environment.

Oil and gas licensing takes place either through licensing rounds or by some of the alternative routes to licensing, section 23 of the Mineral Resources Act (MRA). Licensing rounds have taken place at regular intervals since 2002 for offshore areas (acreage) and there is an open door procedure for designated areas, which require no rounds. The Greenland authorities in the autumn of 2014 opened a number of onshore and offshore licensing rounds and open door procedures covering the period until 2018.

The MRA is to a large extent based on the Danish Subsoil Act and in a number of areas the MRA should – taking into account the Arctic context – be interpreted in a manner similar to the interpretation of the Danish Subsoil Act.

Exploration licences are for a 10- or 16-year period (depending on the exploration area and target) and a commercial discovery gives the licence holder a right to extension of the licence for the purposes of exploitation (production) for a period of up to 30 years. Both exploration and exploitation licences may be prolonged by the authorities.

In accordance with the MRA, the licensee must use Greenlandic labour and use Greenlandic enterprises for contracts for works, supplies and services, unless such local enterprises are not competitive from a financial or technical perspective.

The MRA is supplemented by Model Licences containing standard terms detailing the rights and obligations under the MRA, as well as model Joint Operating Agreements (JOAs). New Model Licences and new versions of the JOAs were issued in September 2014 for both onshore and offshore areas, and for both tendering rounds and open door procedures.

Other legislation that may be relevant for oil and gas activities includes the maritime regulations (transport, marine safety, etc.) in force in Greenlandic waters, and the Large-Scale Act, which governs employment terms and compensation levels for foreign workers employed in large-scale projects.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Rights are transferred through licence. The legal status of those rights or interests under Greenlandic law are both public law rights and contractual rights.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Exploration licences are for a 10- or 16-year period (depending on the exploration area and target) and a licence will contain work obligations during the separate stages of the exploration programme (work programme). A commercial discovery of oil or natural gas gives the licence holder a right to an extension of the licence for the purposes of exploitation (production) for a period of up to 30 years. Both exploration and exploitation licences may be prolonged by the authorities.

Typically, an applicant shall submit an application that contains a work programme with exploration commitments for a total exploration period of 10 (or 16) years divided by three or more sub-periods with specific work commitments for each sub-period. Before the end of each sub-period, the licensee may choose to either surrender the licence or undertake to carry out the work commitments for the next following sub-period. Typically, 30% of the area must be relinquished following each stage. Upon application, the duration of sub-periods may also be extended, typically by three years.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Through Nunaoil, the Greenlandic state participates with a 6.25% share (carried interest) in all hydrocarbon licences. Nunaoil is 100% owned by the Greenland government. The state's rights are a matter of law. The legal basis for the state's participation is Act No. 15 of 7 December 2009 on the establishment of the state company Nunaoil A/S, the MRA and the individual licences.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The state derives value through the participation of Nunaoil, local content obligations and royalties and taxes. Rules regarding the taxation of income from oil and gas activities can be found in the Greenlandic Income Tax Act and in the Model Licences, which set forth the calculation principles that govern the income that is subject to specified royalty/tax rates. A sales royalty of 2.5% has been introduced in the licensing rounds announced in

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September 2014, in addition to surplus royalties calculated on profit levels. Also, fees must be paid for the granting of licences, etc., and the authorities' expenses in connection with the licensee's activities must be reimbursed by the licensee. According to PWC, Greenland's "government take" is 52.5%, compared to 57.7% in the UK, 59.5% in Denmark and 77.7% in Norway.

3.6 Are there any restrictions on the export of production?

Export of production may only take place with the approval of the Greenland government; see section 2(2) of the MRA. Further terms may be set forth in the individual licence or the individual permit.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There is no special currency exchange or transfer of funds restrictions.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The transfer or disposal of oil and natural gas development rights or interests can only take place with the approval of the Greenland government – see section 88 of the MRA – and the authorities may set forth terms and conditions for the transfer, including a detailed review of the financial and/or technical capabilities of the new licensee.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Under section 92(3) of the MRA, a licence may stipulate that the licensee's liability must be covered by insurance or another type of security. Rules have been set forth in the Model Licence, which states that the licensee's activities under the licence shall be covered by insurance, including third-party liability insurance, which shall always provide reasonable cover for any insurance risks. A detailed description of the required insurance programme has also been issued by the authorities. The programme in particular includes requirements for third-party liability insurances, marine insurances and control-of-well insurances.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Licences granted under the MRA cannot be subject to prosecution and can therefore principally not be pledged for security according to section 88(2) of the MRA. A mortgage will in any event require the approval of the authorities. Otherwise, licence assets can be booked for accounting purposes provided the generally accepted accounting principles are adhered to.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Generally, Greenlandic and applicable Danish law must be observed, including the MRA, the Working Environment Act (onshore) and the Marine Environment Act. A number of additional permits and approvals are required, including environmental impact assessments (EIAs), social sustainability assessments (SSAs) and the entering into of impact benefit agreements (IBAs). Other permits include drilling permits and environmental permits. All of the foregoing regulations, permits and agreements are influenced by the fact that exploration and production will take place in an Arctic environment.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Under section 42 of the MRA, specific provisions are laid down in licences on the licensee's obligations for the termination of activities to remove facilities, etc., established by the licensee and to clean up, monitor etc., the affected areas. More detailed rules are contained in article 17 of the Model Licence, according to which all facilities, etc. must be removed unless non-removal has been approved by the authorities.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The MRA also applies other uses of the subsoil than exploration and production, including storage, and including gas storage.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Export of production may only take place with the approval of the Greenland government; see section 2(2) of the MRA. Further terms and conditions may be set by the authorities in the individual permits.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Export of production may only take place with the approval of the Greenland government; see section 2(2) of the MRA. Further terms and conditions may be set by the authorities in the individual permits.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

As there is currently no production of hydrocarbons in Greenland, there are no transportation pipelines or associated infrastructure.

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The regulatory framework is contained in the MRA, which requires authority approvals for establishment of infrastructure and for individual licences. See also the answer to question 6.2 below.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

According to section 2(2)(iv) of the MRA, the establishment and operation of pipelines for activities under the MRA requires the prior approval of the Greenland government. Laying and operating pipelines may also require the preparation and approval of EIAs, SSAs and IBAs. Further conditions may be set in the individual permit.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Applications for the laying and operation of offshore pipelines must be submitted to the government and will follow a rigorous approval process in terms of technical, environmental and economic factors, including EIA, SSA and IBA. Under section 93 of the MRA, the authorities have powers of compulsory acquisition of real property with a view to activities under the MRA.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

As there is no hydrocarbon production in Greenland, and no commercial discoveries have been made, there are currently no oil and natural gas transportation pipelines or associated infrastructure in Greenland. Access to infrastructure is likely to be regulated by the principles set forth in section 28 of the MRA.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

As there is no hydrocarbon production in Greenland, and no commercial discoveries have been made, there are currently no oil and natural gas transportation pipelines or associated infrastructure in Greenland. See also the answer to question 6.6 below.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Under section 28 of the MRA, a licensee may be ordered, against payment, to make processing and transport facilities available for coordination of the exploitation of several hydrocarbon deposits. As so far no commercial discovery of oil and gas has been made in Greenland, the exact administration of third-party access rights and obligations, to be carried out by the authorities, cannot be determined at this stage with any level of certainty.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

See the answer to question 6.6 above.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

There are currently no oil and natural gas transmission or distribution pipelines or associated infrastructure in Greenland as natural gas is not a substantial component of the Greenland energy mix. The Greenland government has under Act No. 14 of 6 November 1997 on Energy Supply awarded an exclusive licence to distribute heat, electricity and water to the company Nukissiorfiit, which is 100% owned by the Greenland government reporting to the Department of Nature, Environment and Justice. With reference to the government and the legislature, Nukissiorfiit carries out all energy supply planning for electricity and heating purposes in Greenland.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Please see the answer to question 7.1 above.

7.3 How is access to the natural gas distribution network organised?

There is no significant natural gas distribution network in Greenland and Nukissiorfiit holds exclusive rights to distribute heat, electricity and water in Greenland.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Please see the answers to questions 7.1 and 7.3 above. Under its exclusive rights, Nukissiorfiit shall ensure the supply to Greenlandic households and enterprises.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Please see the answer to question 7.3 above.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Please see the answer to question 7.3 above. Nukissiorfiit is government-owned and holds exclusive rights as a distributor.

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8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Please see the answer to question 7.3 above.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Please see the answer to question 7.3 above.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

There are no LNG facilities in Greenland. Future LNG facilities in Greenland are likely to be governed by the MRA and/or Act No. 14 of 6 November 1997 on Energy Supply.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Future LNG facilities in Greenland are likely to be governed by the MRA, including section 2(2), which states that the establishment of pipelines and facilities requires the approval of the Greenland government.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Please see the answer to question 9.1 above.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Under section 28 of the MRA, a licensee may be ordered, against payment, to make processing and transport facilities available for coordination of the exploitation of several hydrocarbon deposits. The principles contained in section 28 are likely to also apply to future LNG facilities, at least in the upstream/midstream segments.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream oil sector is regulated by different regulatory frameworks in Greenland. There is regulation by the Environmental Protection Act, the Competition Act, the Marketing Practices Consolidation Act and applicable tax law also regarding environmental tax. Further regulatory framework may apply according to the different stages in downstream oil.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

KNI Polaroil A/S is by far the largest oil trading organisation in Greenland with a very dominant market share of close to 100%. As a part of the KNI group, Polaroil is 100% owned by the Greenland government but is principally working on a commercial basis. Polaroil has 69 facilities throughout Greenland, including 16 storage facilities in major cities and 52 smaller units in towns and settlements.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

Competition law in Greenland is regulated by the Greenland Competition Council (GCC, "*Konkurrencenævnet*"), which is a government body independent from the Greenland government.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Competition is governed by Act No. 1 of 15 May 2014 on competition ("Competition Act") which entered into force on 1 July 2014. The Competition Act prohibits agreements that serve or lead to a distortion of competition. The Act is inspired by the Danish Competition Act, which again is heavily influenced by EU competition law. As is the case under the EU competition rules, the Competition Act is based on a prohibition against anti-competitive agreements, etc., and on a prohibition against abuse of a dominant position.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The powers of the GCC include prohibiting or amending agreements and decisions or granting exemptions. Fines for violating competition law are imposed through the judicial system.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

The Greenland Competition Act is supplemented by executive order No. 3 of 10 March 2016 on merger notification and executive order No. 13 of 23 July 2015 on turnover calculation. The government's approval is furthermore required for the transfer of licence rights, etc., to third parties. The time required for approvals of licence transfers depends entirely on the specific circumstances and the individual licence.

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12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There are no such special requirements on foreign companies. An exploration licence may be granted to both Greenlandic enterprises and foreign companies; however, the holder of an exploitation licence must as the starting point have its registered address in Greenland.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Greenland is a part of the Danish Unity of the Realm and holds only a limited foreign policy capacity. Foreign policy for Greenland is carried out by the Danish government in consultation with the Greenland government. As such, a number of treaties and conventions signed and ratified by Denmark also become relevant for, and applicable to, Greenland. For oil and gas, these include international conventions on the liability for oil pollution in the marine environment. Other selected conventions, e.g. in the environmental area, may not apply to Greenland.

Greenland is not a member of the European Union (EU) but has the status of an associated territory in the EU. Therefore, EU rules do not apply to Greenland apart from the special rules on association of overseas countries and territories (OCT) of the EC Treaty.

Greenland is a member of the World Trade Organisation (WTO) that has established a number of rules, for example, to promote international trade and the provision of services. Greenland is a member of the WTO by virtue of the national community with Denmark. This means that the WTO rules apply also to Greenland. The WTO rules include, for example, the General Agreement on Trade in Services (GATS).

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

There are no specific compulsory dispute resolution procedures applicable to the oil and natural gas sectors. The normal dispute settlement procedures under, *i.a.*, the Greenland civil procedure rules, apply. The Courts of Greenland consists of 18 district courts, the Court of Greenland and the High Court of Greenland. Most cases are heard in the first instance by the district courts. The district court judges are not lawyers but lay judges with a special education and thorough knowledge of the Greenlandic society. The Court of Greenland processes legally complicated cases in the first instance and handles supervision and education of district judges. The judge in the Court of Greenland and the High Court judge of Greenland are lawyers. Rulings issued by the district courts and the Court of Greenland may be brought before the High Court of Greenland. Rulings issued by the High Court of Greenland may, with the permission of the Appeals Permission Board, be brought before the Supreme Court in Copenhagen.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Denmark is a signatory (1972) to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and a signatory (1965) to ICSID. Both of these conventions apply to Greenland.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

There is no special difficulty in litigating or seeking to enforce judgments or awards against government authorities or state organs in Greenland.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are not aware of such litigation in the oil and gas sector. Greenlandic courts are independent from the government and the legislature, and hence there is no reason to believe that foreign corporations should not be able to obtain judgments, etc. against Greenlandic government authorities before the Greenlandic courts.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

In 2014, the Greenland government issued its Oil and Mineral Strategy 2014–2018.

A key point of the Oil and Mineral Strategy is to move the focus of exploration for oil and gas to the West Greenland areas, where ice conditions are less severe and infrastructure and data is more readily available. This includes an offshore Baffin Bay licensing round in 2017 and an offshore Davis Strait licensing round in 2018.

The Government of Greenland has in August 2017 announced the licensing round for applications and granting of exclusive licences for exploration and exploitation of hydrocarbons in offshore areas in Baffin Bay, North West Greenland.

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Licence applications shall be submitted to the Ministry of Mineral Resources no later than 15 December 2017 at 9:00 local time in Nuuk, Greenland.

For an overview of active licences and upcoming licensing rounds and areas, see www.govmin.gl.

Since June 2015, the Greenland National Petroleum Data Repository (GNPDR) portal has been online (www.greenpetrodata.gl). The GNPDR is the Greenlandic National Data Repository for Greenlandic oil and gas-related geophysical and well data.

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Further, from 2012–2015 he was an external lecturer at the University of Southern Denmark. He is the author of the book "*Undergrundsloven med Kommentarer*" (2012) and "*The Greenland Mineral Resources Act – the Law and Practice of Oil, Gas and Mining in Greenland*" (2015).

Bo is a law graduate from the University of Copenhagen (1991) and the Nordic Institute of Petroleum and Maritime Law, University of Oslo (1990), and holds an executive MBA from Copenhagen Business School (1995).

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Chapter 15

Indonesia

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Ranked as the 10th largest gas producer in the world, Indonesia's proven natural gas reserves were recorded in the *BP Statistical Review of World Energy 2017* ("BP 2017 Report") at 101.2 trillion cubic feet. Gas production reached 69.7 billion m^3. Of the foregoing production, 21.2 billion m^3 was exported as LNG and 8.8 billion m^3 was exported through pipelines. According to SKK Migas data, LNG exports and pipeline exports as of September 2017 amounted to 29.08% and 12.56%, respectively, of total gas utilisation.

According to the *PwC Oil and Gas Guide 2017* ("2017 PwC Guide"), Indonesia has the 6th largest Coal Bed Methane ("CBM") reserves in the world at 453 Tcf. Shale gas reserves are estimated at 574 Tcf.

Indonesia's main areas for oil production are Sumatra, the Java Sea, East Kalimantan and Natuna, whereas the main areas for gas production are South Sumatra, East Kalimantan, Natuna, Sulawesi and West Papua.

In 2017, a number of upstream projects have been declared as strategic projects by the Government of Indonesia ("Government") in an effort to increase oil and gas production. These include Tangguh Train-3, the Chevron Indonesia Deepwater Development ("IDD") Project, the Jangkrik Field Development Project and the development of the Jambaran-Tiung Biru block and Genting's Kasuri block.

LNG facilities in Indonesia include Bontang (East Kalimantan), Tangguh (West Papua) and the newest LNG facility, Donggi Senoro (Sulawesi). In a 15-year roadmap published by the Directorate General of Oil and Gas ("DGOG") in April 2016, the Government forecast a need for USD 24.8 billion in investment to enhance gas infrastructure.

A national gas transmission and distribution network has been developed by the Ministry of Energy and Mineral Resources ("MEMR"). Gas pipelines and storage facilities may be owned and operated by private companies, subject to the regulations of the MEMR and the Downstream Oil and Gas Regulatory Agency ("BPH Migas").

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

In 2016, natural gas satisfied roughly 19% of Indonesia's total energy requirements.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Currently, Indonesia's natural gas requirements are fully met by domestic production, particularly by the allocation of the domestic market obligation ("DMO") from every Production Sharing Contract ("PSC") Contractor. PSC Contractors are required by law and contract to reserve 25% of their oil and gas production for the domestic market. According to the BP 2017 Report, the ratio of Indonesia's natural gas production to consumption in 2016 was 185%.

This is expected to change. According to the *BP Statistical Review of World Energy 2016* report, the MEMR projects that Indonesia will start importing natural gas by 2019.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Nearly half of Indonesia's gas production is exported. According to the BP 2017 Report, in 2016, LNG exports reached 21.2 billion m^3 to eight countries, including China, Japan, Mexico and South Korea. During that same period, 8.8 billion m^3 was exported by pipeline to Singapore and Malaysia.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

According to the BP 2017 Report, there were 3.3 billion barrels of proven oil reserves in Indonesia as of the end of 2016, putting Indonesia in the top 20 of the world's oil producers. Oil production reaches 881,000 barrels of oil per day. This marks a 4.8% increase from the production rate in 2016.

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The *SKK Migas Annual Report* in 2016 recorded that after terminating 67 PSCs in 2016, at the end of 2016, Indonesia had a total of 280 PSCs, comprising 85 PSCs in production stage and the remaining 195 in the exploration stage.

Roughly 75% of oil upstream activities are focused in western Indonesia, with the main areas for oil production being Sumatra, the Java Sea, East Kalimantan and Natuna. The Government has been encouraging exploration activities in eastern parts of Indonesia, where, according to the 2017 PwC Guide, 39 tertiary and pre-tertiary basins show rich promise in hydrocarbons. Major companies are involved in oil exploration and exploitation in Indonesia, including Chevron Pacific Indonesia, Total E&P, ConocoPhillips and ExxonMobil.

In the downstream sector, there are 10 oil refineries in the country with a combined installed capacity of 1.155 million barrels per day.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

In 2016, oil satisfied roughly 41% of Indonesia's energy requirements.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

According to the BP 2017 Report, Indonesia's oil consumption in 2016 reached 1.6 million barrels per day, 55% of which was met by domestic production.

2.4 To what extent is your jurisdiction's oil production exported?

According to MEMR data, Indonesia exported 115,017 thousand barrels of oil in 2015. Indonesia's Statistics Central Body recorded Japan and Thailand as the top two countries Indonesia exports oil to, respectively at 3,654.8 thousand tonnes and 2,190.1 thousand tonnes. The MEMR projects that oil exports will continue to decline as domestic production slows.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Indonesia's oil and gas sector is governed by Law No. 22 of 2001 regarding Oil and Gas (November 22, 2001) (the "Oil and Gas Law"). The State retains mineral rights throughout Indonesian territory and the Government holds the mining authority.

The oil and gas sector comprises upstream and downstream activities, which are separately regulated and organised. Upstream activities include exploration and exploitation and are regulated under Government Regulation No. 35 of 2004 regarding Upstream Oil and Natural Gas Business Activities, as has been amended several times, the latest by Government Regulation No. 55 of 2009 ("GR 35"). The upstream sector is managed and supervised by the Special Task Force for Upstream Oil and Natural Gas Business Activities ("SKK Migas").

Due to the unique territorial composition of the archipelagic state of Indonesia, upstream oil activities may be undertaken in onshore and offshore areas. Work areas for onshore and offshore operations are determined by the MEMR based on consultations with and recommendations from the respective regional governments.

Downstream activities encompass processing, transportation, storage and trading, and are regulated under Government Regulation No. 36 of 2004 regarding Upstream Oil and Natural Gas Business Activities, as has been amended by Government Regulation No. 30 of 2009 ("GR 36"). Downstream operations fall under the auspices of the MEMR and BPH Migas.

Through Government Regulation No. 79 of 2014, the Government has stipulated national energy policy to be implemented from 2014 to 2050, focusing primarily on energy availability for national needs, prioritisation of energy development, utilisation of national energy resources and national energy reserves. The target for the availability of primary energy, which includes natural oil and gas, is approximately 400 million tonnes of oil equivalent ("MTOE") in 2025 and approximately 1,000 MTOE in 2050.

In early 2016, the President of Indonesia, Joko Widodo, announced a list of national strategic projects, which include several downstream oil and gas projects, namely the development of the Bontang and Tuban refineries, upgrading existing refineries and construction of the Banten LPG terminal, Belawan–Sei Mangkey gas pipelines, an LNG mini-refinery and an LNG-LNCG station on Java Island. A Presidential Decree and Presidential Instruction seek to accelerate these projects and mandate enhanced cooperation among relevant Government institutions for the achievement of these objectives.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Private companies earn the right to explore and exploit oil and gas resources by entering into cooperation contracts, mainly based upon a production sharing scheme, with the Government (through SKK Migas), thus acting as a Contractor to SKK Migas. One entity can hold only one PSC, and a PSC is normally granted for 30 years, typically comprising six plus four years of exploration and 20 years of exploitation. All financial risks of operations under the PSC are borne by the Contractor. If a work area proceeds to the exploitation stage, the Contractor is entitled to cost recovery.

In the traditional production sharing scheme that has been used over the past years in Indonesia, the production output is typically subject to a first tranche petroleum ("FTP") requirement, cost recovery and certain taxes, and the remaining portion is distributed among the Contractor and the Government in the proportions set out in the PSC (the "Cost Recovery PSC"). In early 2017, the Government, through MEMR Regulation No. 8 of 2017 regarding Gross Split PSC, as amended by MEMR Regulation No. 52 of 2017 ("MEMR Reg. 8/2017"), introduced the gross-split production sharing scheme, in which the production output is split at gross (without FTP, cost recovery or tax deductions) in a sharing proportion stipulated at the beginning of a field development and subject to fluctuation depending on certain various variables and progressive components (the "Gross Split PSC").

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3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

In both Cost Recovery PSC and Gross Split PSC contexts, when a commercial discovery is made, the Contractor must prepare a Plan of Development ("POD") for the relevant field. The first POD is approved by the MEMR based on the considerations of SKK Migas and kicks off the exploitation stage. Subsequent PODs are approved by SKK Migas.

Other authorisations differ in each PSC model.

For a Cost Recovery PSC, expenditures throughout the PSC term are planned ahead by the Contractor in an annual Work Plan and Budget ("WP&B") to be approved by SKK Migas. A Contractor must also prepare an Authorisation for Expenditure ("AFE") for specific work and can only execute the work upon SKK Migas' approval of the relevant AFE.

For a Gross Split PSC, as there is no cost-recovery mechanism, SKK Migas only approves the annual work plan. The budget is only presented to SKK Migas for its consideration in approving the annual work plan, but is not subject to SKK Migas approval. SKK Migas has the authority to adjust the production split for each field by considering the progressive components stipulated in MEMR Reg. 8/2017.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Extracted oil and gas remains owned by the State until it passes the point of export or other delivery point. Thereafter, the Government is entitled to a certain percentage of the production output as apportioned under the PSC, as is the Contractor.

Under the Oil and Gas Law, entities in the form of a State-owned enterprise ("SOE"), regional-owned enterprise ("BUMD"), a cooperative, small business or private business entity may enter into a PSC with SKK Migas to undertake upstream oil and gas business activities. Pertamina, as an SOE and the State oil company, can hold participating interests in numerous PSCs as a Contractor of SKK Migas. There is no maximum limit on the participating interest that an SOE, BUMD or Pertamina may hold.

Upon the first POD approval, a Contractor is required to offer 10% Participating Interest ("PI") in its PSC to a BUMD that is (i) owned at least 99% by the regional government and the remaining by an regional government-affiliated entity, (ii) established pursuant to a regional government regulation, and (iii) does not conduct any business activity other than management of such offered PI. The BUMD may accept or decline the offer based on its financial capability, and in the latter event the offer must be tendered to an SOE.

In addition, MEMR Regulation No. 15 of 2015, as amended by MEMR Reg. 30 of 2016 (as amended, "MEMR 15/2015"), stipulates that Pertamina may elect to resume the operations of a work area whose PSC is expiring, irrespective of whether the initial Contractor has applied for an extension. If both Pertamina and the initial Contractor express a willingness to operate a work area, the MEMR would have the authority to decide whether the operation would be resumed by Pertamina, the initial Contractor or jointly between the two.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Indonesia does not impose royalties on PSCs, but secures the State's minimum income through the FTP mechanism in Cost Recovery PSCs. FTP is the first take of oil or gas immediately after production in a work area in one calendar year that is received by the State prior to cost recovery and profit calculation. FTP therefore secures the State's minimum income. The amount of FTP is determined in the relevant Cost Recovery PSC.

Taxes applicable to PSCs include income tax, VAT, import duties, regional taxes and other levies. The PSC may stipulate whether the tax laws and regulations applicable at the time of the PSC execution shall apply (stabilised) or whether the PSC shall follow every tax law and regulation issued over time. In addition, Contractors are required to pay non-tax State revenues such as exploration and exploitation fees and bonuses, including signing bonus and production bonus.

The sharing proportion between the Government and the Contractor for a Cost Recovery PSC is typically 85:15 for oil and 70:30 for gas, respectively. For a Gross Split PSC, the initial sharing proportion between the Government and the Contractor is 57:43 for oil and 52:48 for gas, respectively.

3.6 Are there any restrictions on the export of production?

Subject to obtaining requisite export approvals, a Contractor is entitled to export its production entitlement, subject to its DMO by which 25% of the Contractor's entitlement must be allocated for the domestic market.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

The Indonesian Currency Law and Bank Indonesia ("BI") Regulation No. 17/3/PBI/2015 regarding the Mandatory Use of Rupiah restrict most transactions within Indonesian territory from being carried out using foreign currency. Core upstream activities in Indonesia are exempted from this requirement for a certain period of time, such as expenditures in relation to firm commitment, over/under lifting and domestic oil and gas sales transactions by upstream players, which are exempted for 10 years.

Bank Indonesia also requires all oil and gas export proceeds be deposited in a foreign exchange bank in Indonesia before being remitted overseas. This requirement is contained in BI Regulation No. 16/10/PBI/2014 as amended by BI Regulation No. 17/23/PBI/2015 regarding Receipt of Export Proceeds in Foreign Exchange and Withdrawal of Offshore Loan Foreign Exchange.

A Minister of Trade ("MOT") regulation issued in 2015 requires that the export of oil and gas products, such as crude oil, condensed oil, liquefied natural gas, compressed natural gas and vacuum residue, shall be paid through a Letter of Credit ("L/C") received from a foreign exchange bank in Indonesia. However, the MOT may suspend this requirement for any exporter that cannot yet implement the obligation to use L/C as its method of payment. This suspension may be granted for a limited period of time and is subject to the consideration from the relevant technical ministry, i.e., the MEMR through the DGOG.

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3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

During the Firm Commitment period, a Contractor is not allowed to (i) transfer the majority of its PI to a non-affiliated party, or (ii) transfer a certain percentage of its PI that would result in the PI transferee holding a higher percentage of PI than any other initial Contractors. Change of operatorship in a PSC during the Firm Commitment is also prohibited. After such period, transfer of PI may be conducted upon approval of the MEMR based on the consideration of SKK Migas.

A PSC typically provides an approval or notification requirement for the transfer of all or a portion of the Contractor's PI to an affiliate or non-affiliated third party. From 2007 onwards, PSCs have stipulated that transfers of participating interests to affiliates and changes of control in a party to a PSC require prior written consent of the MEMR (through SKK Migas). Similarly, MEMR Regulation No. 48 of 2017 ("MEMR Reg. 48/2017") stipulates that a transfer of participating interest in a PSC requires prior approval of the MEMR.

GR 35 also imposes a requirement that if all or a portion of the rights of the Contractor are transferred to a non-affiliate or to another company that is not a partner in the same working area, the MEMR can "request" that the Contractor offer the interest to a national company.

Any transfer of PI must follow the guidelines and procedures stipulated in SKK Migas Working Guidelines ("PTK") No. 057 of 2014 regarding the transfer of participating interests. The party receiving the transfer is subject to SKK Migas' review and approval since an entity must possess the requisite financial capability and skills to hold PI in a PSC.

Pursuant to MEMR Regulation No. 48 of 2017 ("MEMR Reg. 48/2017"), indirect transfer of PI through transfer of shares of the Contractor requires MEMR approval with SKK Migas' consideration if the transfer pertains to majority shares, thus resulting in a direct change of control of the Contractor. If the transfer results in an indirect change of control of the Contractor, the transfer needs only to be reported to the MEMR through SKK Migas.

In addition, the direct and indirect transfer of PI as well as change of control is subject to taxes imposed by Government Regulation No. 79 of 2010 as amended by Government Regulation No. 27 of 2017 (as amended, "GR 79/2010"), and Minister of Finance ("MOF") Regulation No. 257/PMK.011/2011.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

A Contractor must provide a performance bond by the time of execution of the PSC, which amount depends on the type of the contract area. The performance bond for open areas, a portion of the contract area that is carved out based on PSC and areas for which the PSC has expired, is 10% of the total Firm Commitment value, with a minimum sum of USD 1.5 million. Areas that have never been developed or are being or have been produced are subject to performance bond in an amount equivalent to 10% of the WP&B for the first two years of the exploration period, with a minimum sum of USD 1 million.

Further, a parental guarantee may be required by SKK Migas for a company intending to acquire PI in a PSC, subject to SKK Migas' assessment of the company's audited financial statements.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

PI cannot be pledged as security. This is primarily because a PI transfer can only be conducted upon approval of the Government, and there is no guarantee that the Government will approve the transfer of PI to the pledgee if execution comes.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

In conducting petroleum activities, PSC Contractors are required to comply with the provisions of occupational health and safety, environmental management and community development regulations. In the exploration phase, PSC Contractors must complete an environmental monitoring and environmental management ("UKL/UPL") report. During the exploitation of a proposed development, PSC Contractors must further conduct an environmental assessment ("AMDAL"), which is subject to the relevant Government authority's approval. PSC Contractors are also required to make periodic reports to the relevant Government authorities regarding their compliance with the UKL/UPL or AMDAL. In addition, the Environmental Law requires PSC Contractors to obtain an environmental licence from the Minister of Environment and Forestry.

The DGOG is responsible for supervising the implementation of health, safety and environment ("HSE") regulations in the oil and gas sector and imposing sanctions for non-compliance. The DGOG designates Mining Inspection Enforcement teams to examine work safety compliance in oil and gas businesses. If the facilities and techniques satisfy work health and safety standards, the DGOG shall issue certifications for installations and equipment. Non-compliance with applicable HSE rules subjects the company to administrative sanctions up to revocation of the licence.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

New-generation PSCs stipulate an express obligation to carry out an abandonment and site restoration ("ASR") programme and to provide ASR funds.

The Oil and Gas Law highlights post-operation obligations as a means of ensuring environmental management and protection, and GR 35 obligates Contractors to allocate funds for post-operation activities. MEMR Reg. 15/2015 also stipulates that outstanding post-operation obligations of a PSC nearing expiry are to be carried out by the entity that has been appointed by the MEMR to resume the PSC, which could be PT Pertamina (Persero) and/or another Contractor. More specific decommissioning obligations are contained in various regulations, such as MEMR Regulation No. 02P/1992, which requires land reclamation, and Government Regulation No. 17 of 1974 Regarding Supervision of Implementation of Offshore Oil and Gas Exploration, which requires dismantlement of facilities that are no longer used. A PTK in 2015 on Work Completion Approval also lists well-plugging as one of the items constituting completion of drilling work. The procedures to reserve and deposit ASR funds are set forth in PTK 040/2010.

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3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/ requirements of the legislation?

Gas storage is generally regulated under GR 36 as a downstream activity. Gas storage activities may be conducted upon obtaining a storage licence from BPH Migas, except if the gas storage activities are ancillary to the entity's main processing, transportation or trading activities. A company engaging in gas storage business is obligated to offer facility sharing to a third party by considering the technical and economic aspects. Facility sharing is specifically regulated under BPH Migas Regulation No. 6 of 2005.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Cross-border sales of natural gas can only be conducted if (i) domestic need for natural gas has been fulfilled, (ii) there is insufficient domestic infrastructure, or (iii) domestic purchasing power is insufficient to satisfy the relevant gas field's economics. Pursuant to MEMR Regulation No. 6 of 2016 regarding Provisions and Procedures for Stipulating the Allocation and Utilization as well as Pricing of Natural Gas ("MEMR Reg. 6/2015"), the allocation of natural gas production is prioritised for (i) the Government's programme to provide natural gas for transportation, households, and small-scale customers, (ii) increase of national oil and gas production, (iii) the fertiliser industry, (iv) industries that use natural gas as a raw material, (v) the provision of power, and (vi) industries that use natural gas as fuel. Cross-border deliveries of natural gas are subject to import or export approvals from the Minister of Trade, which takes into account the import or export recommendation from the DGOG. The DGOG considers domestic supply and demand in issuing such recommendation.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Cross-border sales of oil are subject to fulfilment of the DMO (for upstream players). As discussed in question 4.1 above, cross-border deliveries of natural gas are subject to import or export approvals from the Minister of Trade, which takes into account the import or export recommendation from the DGOG. The DGOG considers domestic supply and demand conditions in issuing such recommendation.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Gas transportation by pipeline is regulated under GR 36 and MEMR Regulation No. 19 of 2009 regarding Natural Gas Business through Pipelines, and is controlled by BPH Migas. It can only be carried out by a business entity established in Indonesia that has obtained a transportation licence from the MEMR, unless such transportation is conducted by a PSC Contractor as a continuation of its upstream activities.

The MEMR, as mandated by the Oil and Gas Law, has established a transportation master plan. This master plan is relied upon by BPH Migas to, *inter alia*, determine transmission routes and distribution networks, tender Special Rights, and to determine tariffs in accordance with techno-economic principles.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

In addition to a gas transportation licence from the MEMR, a business entity must also obtain Special Rights from the MEMR to transport gas by pipeline within the stipulated transmission and distribution routes by way of tender. An environmental licence must also be obtained by preparing the relevant environmental document, which can be an AMDAL or a UKL/UPL, depending on the length and pressure of the pipelines.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Generally speaking, land rights will be obtained by negotiating with owners and occupiers, in accordance with prevailing laws. To the extent these facilities are used for upstream activities within the framework of a cooperation contract, the Contractor will have to comply with the Oil and Gas Law, GR 35 and the relevant implementing regulations to be issued thereunder. Contractors are responsible for the payment of these rights. Land that is purchased for a facility will become the property of the State, while land that is leased for a facility will be leased in the name of the Contractor.

Title to land purchased for facilities used for downstream activities outside of a cooperation contract may be held in the name of the business entity engaging in the transportation or storage activity.

Projects that serve the public interest may enjoy more Government involvement in the land procurement process, as stipulated in Presidential Regulation No. 71/2012 as has been amended several times, lastly by Presidential Regulation No. 148/2015. The President has also issued a regulation and an instruction to enhance cooperation among governmental entities in smoothing the preparation and operation of nationally strategic projects.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Access to oil and natural gas transportation pipelines and associated infrastructure is organised by BPH Migas by relying upon the transportation master plan stipulated by the MEMR.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The MEMR periodically stipulates a transportation master plan for

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natural gas that is relied upon by BPH Migas in controlling and supervising the implementation of gas transportation activities by business entities, including determining the joint use of transportation and storage facilities as well as associated infrastructure.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

A pipeline or storage facility operator cannot be required to expand its facilities to accommodate new customers. Facility sharing is obligated by GR 36 only to the extent the relevant facility has sufficient capacity so that the facility sharing will not impair the operations of the facility owner. Facility sharing is also subject to economic considerations, such as the facility owner's investment return rate. BPH Migas is the authority that oversees and regulates facility sharing.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

In general, and subject to BPH Migas' authority to set tariffs for the transportation of natural gas through pipelines, parties may agree on the terms of the agreement for the transportation and storage of natural gas. A "contractual regime" is in its early stages of evolution.

BPH Migas has the authority to determine and supervise the tariffs for natural gas transportation through pipelines that will be charged by the operator of the pipeline to the users. The relevant operator must submit the proposed tariff to BPH Migas. BPH Migas will then verify and evaluate the proposed tariff. BPH Migas will discuss with the related pipeline operator and the users before determining the tariff.

For the transportation of natural gas, the applicable regulation provides that the agreement between a gas pipeline operator and user must be set forth in a gas transportation agreement. The regulation also requires the operator of the gas pipeline to prepare an access arrangement outlining the terms and conditions for the joint use of the pipelines owned by the operator. This, as well as the tariff, must be approved by BPH Migas. The access arrangement will include management guidelines and technical and legal rules. The gas transportation agreement must be in accordance with the access arrangement.

Crude oil transportation is not subject to the Government's approval, whereas fuel oil is relatively more heavily regulated in terms of distribution, pricing and availability.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Please refer to question 6.1 above.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Please refer to question 6.2 above.

7.3 How is access to the natural gas distribution network organised?

Please refer to question 6.4 above.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

No. This requirement only applies to gas transportation and processing activities.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Under Government Regulation No. 1/2006, the monthly fees charged for accessing the gas distribution network are 3% or 2% of the transmission tariff per one thousand standard cubic feet for up to 100 billion standard cubic feet or above 100 billion standard cubic feet, respectively.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Direct acquisitions of an interest in a gas utility or the transfer of assets forming part of the distribution network will require revocation of the existing Special Right and issuance of a new Special Right to the acquirer. Indirect acquisitions or transfers of assets (by way of share transfers) may be subject to foreign share ownership restrictions regulated under the Negative Investment List (see question 12.1 below).

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Natural gas trading is governed under GR 36. It must be conducted by a business entity established in Indonesia by obtaining a trading business licence from the MEMR. The trading business licence is further categorised into wholesale trading and limited trading, depending on the scale of business and ownership of facilities.

Natural gas trading must adhere to the provisions of priority businesses as well as the price stipulation under MEMR Reg. 06/2016.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

This will depend on how BPH Migas regulates distribution and

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trading activities and whether the Government will issue multiple trading and distribution licences for a given area. Bundling of several products is possible since one entity may hold both a distribution and a trading licence.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

LNG facilities may be operated by upstream players as an ancillary activity to their main activities under the PSC, or by a downstream business entity that engages in processing or trading activities.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Prior POD approval from the MEMR is required for the operation of LNG facilities at the upstream level. At the downstream level, the construction and operation of LNG facilities must obtain a processing or wholesale trading licence from the MEMR. In both sectors, it may be necessary to obtain other relevant licences from central and regional governments, such as licences related to HSE and land.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Gas pricing is stipulated by considering the economics of fields, domestic and international gas prices, and added value from the domestic utilisation of natural gas. The stipulation of gas prices for domestic needs must also consider the purchasing power of domestic consumers as well as support for the Government's programme to provide natural gas for transportation, households and small-scale customers.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Please refer to question 6.6 above.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Downstream oil activities are regulated in GR 36. It encompasses oil processing, storage, transportation and trading, each of which requires a specific licence from the MEMR. A downstream company is allowed to carry out an ancillary downstream activity as a supporting activity to its main business without obtaining a separate business licence, provided that the other downstream activity is not used to generate profit, in which case the company must obtain a separate licence.

Only business entities established in Indonesia are eligible to obtain downstream business licences, subject to the applicable foreign shareholding restriction stipulated in the Negative Investment List.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Depending on the oil commodities being traded, oil trading activities fall under the auspices of the MEMR or BPH Migas. In addition to the downstream licence from MEMR, trading of oil fuel can only be conducted after registering the specific type of oil fuel with BPH Migas and obtaining a Business Registration Number ("NRU") from BPH Migas. Oil trading is classified into wholesale trading and limited trading, depending on the scale of business and ownership of facilities.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

While BPH Migas can impose penalties on business entities engaged in the natural gas sector, the Commission for the Supervision of Business Competition ("KPPU") is responsible for implementing Indonesia's Anti-Monopoly Law. The KPPU may issue decisions that certain agreements, conduct or positions in the relevant market (including the natural gas market) are anti-competitive and therefore in violation of Law No. 5 of 1999 regarding Prohibition of Monopolistic Practices and Unfair Business Competition (the "Anti-Monopoly Law").

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The provisions and criteria on anti-competition are regulated under the Anti-Monopoly Law. The prohibitions can be categorised as follows: prohibited agreements; prohibited conduct; and abuse of a dominant position in a given market sector.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The KPPU is not necessarily authorised to preclude anti-competitive practices. However, should the KPPU deem certain agreements, conduct or positions in the relevant market (including the oil and gas market) in violation of the Anti-Monopoly Law, it may lawfully issue decisions and sanctions. The KPPU also has the authority to provide advice, on request, regarding a planned merger, consolidation or acquisition of companies. This advice does not constitute the KPPU's approval or rejection of the planned restructuring scheme and does not preclude the KPPU from performing an assessment of the merger, consolidation or acquisition after the same is effectuated.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

The MEMR has the authority to approve a transfer of shares of a Contractor that will result in a direct change of control of the Contractor, although the MEMR's consideration in granting its approval is not focused on competition issues. The MEMR's approval or rejection of the transfer of shares shall be issued within 28 working days as of SKK Migas' receipt of the correct and complete application.

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Prior consultation with the KPPU can only be conducted for mergers, consolidations and acquisitions. Upon the KPPU's assessment of the relevant documents, the KPPU shall issue its advice, guidance or written opinion regarding the proposed restructuring to the concerned business actors within 90 days of the submission of the required documents.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

The New Negative Investment List, as recently issued in Presidential Regulation No. 44 of 2016 regarding List of Business Fields that Are Closed and Business Fields that Are Open with Requirements in the Field of Capital Investment, stipulates the foreign shareholding limitations for various business fields. Among others, onshore drilling is closed to foreign investment while offshore drilling is restricted to a maximum of 75% foreign shareholding.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

As a matter of international law, international treaties and other multinational agreements are binding upon the State upon ratification. Ratification of such international instruments is normally done by way of a presidential regulation, which will be further implemented by a ministerial regulation. All regulations and decrees issued afterward must not deviate from the provisions of the international treaty or the national regulation enacted in light thereof. Therefore, once an international treaty is binding upon the Government, regulatory policy or activity shall develop in accordance with the international treaty. Among others, Indonesia is a party to the United Nations Convention on the Law of the Sea ("UNCLOS"), the 1987 Montreal Protocol and the International Convention on Civil Liability for Oil Pollution Damage and the protocols and amendments thereof.

Additionally, tax treaties and bilateral investment treaties may be relevant, although the Government recently announced that Indonesia will be withdrawing from all bilateral investment treaties to which it is a party.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

In the upstream sector, the dispute resolution mechanism is stipulated in the PSC. Pursuant to PTK 007, as has been amended several times, disputes in relation to service providers to upstream business as well as the procurement thereof may be resolved in court or through arbitration held in Indonesia in accordance with the provisions of the contract. In the event of a dispute between a Special Rights holder in relation to the implementation of gas transportation by pipeline, BPH Migas has the authority to intervene. If such intervention does not yield a settlement between the disputing parties, the dispute may be referred to a district court.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Yes, Indonesia is a signatory to and has ratified both.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

Indonesia does not recognise foreign court decisions, but international arbitration awards can be enforced in Indonesia through the mechanism provided in Law No. 30 of 1999 regarding Arbitration and Alternative Dispute Resolution (the "Arbitration Law"). In general, Indonesia has bound itself to enforce foreign arbitral awards if (i) the award is rendered by a tribunal in a country bound by the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards or a bilateral treaty with Indonesia, (ii) the dispute is commercial in nature, as that term is understood under Indonesian law, and (iii) the award does not contravene Indonesian law or notions of public order or policy.

Enforcement of international arbitral awards in Indonesia against Government authorities or State organs appears to be difficult. A precedent for this is *Karaha Bodas v. Pertamina*, where an Indonesian court annulled an arbitral award in favour of Karaha Bodas.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

Not to our knowledge.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

A draft of a new oil and gas law, which is widely expected to reform the oil and gas regulatory framework, is being prepared by the House of Representatives. Expected changes include the establishment of oil and gas managing agencies in the form of State-owned enterprises to replace SKK Migas, increased privileges for Pertamina in acquiring work areas, the contracts or licensing mechanisms in the upstream sector, the prescribed maximum period for exploration activities and an obligation to dedicate production

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to the domestic market through a Safeguarding Business Entity established by the law itself.

In 2017, the Government issued a revision to GR 79/2010 that is intended to encourage upstream activities in the midst of falling oil prices. The revisions include (i) stipulation of Holiday DMO Compensation, tax incentives and non-tax State income incentives, (ii) recoverability of social development costs in exploration and exploitation stages, and (iii) changes to the list of costs that are not recoverable. The MEMR issued Regulation No. 26 of 2017, as amended by Regulation No. 47 of 2017, to further detail the cost-recovery mechanism. One of the key provisions provides for a cost-recovery mechanism in the event a PSC is not extended and there are unrecovered costs at the expiration of the PSC, in which case the new PSC Contractor shall agree on the settlement of cost-recovery amounts with the existing PSC Contractor. The operating costs that can be settled in this context are operating costs for the last five years of the PSC term. This Regulation also provides that the MEMR can stipulate an amount of investment costs that can be recovered by taking into account the economic value of the upstream oil and gas activity. The MEMR can also determine the recovery of investment costs in the absence of a succeeding PSC Contractor at the end of the PSC period.

The key regulations issued by the MEMR in 2017 include MEMR Reg. 8/2017, which introduces the gross split mechanism (see question 3.2 above), and MEMR Reg. 48/2017, which governs, among other things, the provisions and procedures for change of ownership, change of control and change of management of a Contractor (see question 3.8 above).

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Syahdan received his Bachelor of Laws in economic law from the University of Indonesia. He earned his Master of Laws after completing a one-year programme in international economic and business law at the University of Groningen, the Netherlands.

Syahdan's recent projects include advising an Indonesian State-owned oil and natural gas company on the acquisition of a petrochemical company and acting for a Japanese petroleum company on fuel sale and storage agreements. He advised a leading multinational energy corporation on its potential exposure on the retirement of certain offshore and onshore assets and acted for a multinational drilling rig operator in a potential cooperation in Indonesia.

Syahdan is a member of the Indonesian Advocates Association.

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Italy

Fiorella F. Alvino

Ughi e Nunziante – Studio Legale

Giovanna Branca

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Italy has experienced a profound change in domestic economic policies, determined by a different theoretical approach to the role of the State in the economy, which has reduced direct participation in regulatory activities. This change led to the launch of a privatisation process that is affecting all of the most important State-run businesses and, thanks to EU directives, to the opening up of competition in those areas traditionally considered natural monopolies.

Thus, the overlapping of liberalisation and privatisation processes at both a national and European level has made it impossible to maintain the traditional approach to energy policy based on the direct intervention of the State in ensuring the pursuit of the priority objectives of the public service and security of supply. The State has thus changed its energy policy goals from its decision-making position to that of utilities sector regulator.

With these objectives and on these assumptions, the European Parliament and the Council of the European Union issued various directives in the 1990s to try to liberalise the gas sector, the most important being Directive 98/30/EC, which outlines the regulatory framework which all EU countries will have to follow.

In Italy, it was transposed by Legislative Decree no. 164 of 23/05/2000, the so-called "Letta Decree" (from the then Minister of Industry). This decree completely revolutionised the gas sector in Italy: from an integrated vertical market fully concentrated in the hands of the State monopoly of Eni to a market open to competition during production, supply and sale.

The legislative process was further pursued at Community level, as a new European directive was adopted in the first half of 2003, which incorporates much of Directive 98/30/EC and continues with the liberalisation of the gas market.

In relation to the so-called "Second Gas Directive" (2003/55/EC), many of the provisions contained therein were actually implemented in national legislation more stringently than required as a minimum by EU legislation.

This refers in particular to the rules of legal, organisational and decisional separation introduced by the Authority for Energy and Gas Services and the Integrated Water System (AEEGSI) with Resolution no. 11/07 in order to substitute the effects of a real proprietary separation. In fact, this has extended the scope of application of the functional unbundling to activities different from transport and distribution (i.e. storage to LNG), and on the other hand has envisaged the adoption of a very penetrating model of governance aimed at regulating relations between the parent company and subsidiaries in order to:

- guarantee the neutrality of the management of infrastructures essential for the development of a free energy market;
- prevent discrimination in accessing commercially sensitive information; and
- prevent the cross-transfers of resources between the segments of the supply chain.

The constant path towards greater market competitiveness has been implemented with:

1. Legislative Decree no. 93/11, acknowledging the so-called "Third Energy Package";
2. Legislative Decree no. 130 of 13/08/2010, (the so-called "Storage Decree") and subsequent amendments; and
3. the AEEGSI's resolutions on gas balancing.

The storage activity allows a dynamic optimisation of the available infrastructure in order to satisfy users' demand.

In Italy, it is an activity subject to concession by the Ministry for Economic Development (MiSE), and the main operator is Stogit which manages about 96% of the total storage capacity, with nine operating concessions, 16.5 billion cubic metres of capacity and 20 billion cubic metres of gas handled in the storage system in 2016. The remaining portion is managed mainly by Edison Stoccaggio.

The tariff, defined on the basis of criteria established by the AEEGSI and approved by the latter every year, is the lowest in Europe. The storage system is managed by each operator as a single integrated system (hub) for which users access a single tariff at national level. Through a perception system, the two storage companies receive their reference revenues approved by the authority. The rules for access to capacity and storage facilities are laid down by the AEEGSI.

The national gas system is fuelled by about 90% of imported gas.

The major import infrastructures in operation are:

- the TAG pipeline for the import of gas originating from Russia, which is connected to the National Pipeline Grid in Tarvisio (Udine);
- the Transitgas pipeline for the import of Dutch and Norwegian gas, which goes from Wallbach, located in Switzerland, up to Passo Gries (VB), where it is connected to the National Pipeline Grid;

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- the TTPC (Trans Tunisian Pipeline Company) pipeline, which crosses the Strait of Sicily up to Mazara del Vallo (TP), where it is connected to the National Pipeline Grid;
- the Greenstream pipeline, which connects Libya and Italy at the entry point of Gela;
- the regasification plant of the company GNL Italia al Panigalia (La Spezia);
- the Adriatic LNG terminal, which is a regasification terminal off the coast of Rovigo; and
- the OLT Offshore LNG Toscana, which is a floating regasification terminal off the coast of Livorno in Tuscany.

The following entry point is currently being built:

- the TAP (Trans Adriatic Pipeline) pipeline, which will be an interconnector pipeline between Greece and Italy through Albania, with an entry point in Italy at the Municipality of Melendugno, in Puglia.

The following projects have been authorised:

- the IGI Poseidon pipeline (Company: IGIPoseidon), which should be an interconnector between Greece and Italy, with an entry point in Otranto (Lecce);
- the regasification terminal offshore (Company: Api Nova Energia) of Falconara Marittima in the Marche Region; and
- the regasification terminal (Company: LNG Medgas Terminal) of Gioia Tauro in the Calabria Region.

The following projects are under evaluation:

- the GALSI pipeline (Company: Galsi S.p.A.) from Algeria to Sardinia and then from Sardinia to Toscany; and
- the regasification terminal of Monfalcone (Company: Smart Gas S.p.A.) in the Friuli Venezia Giulia Region. The outcome of the Environmental Impact Assessment (VIA) has been negative.

Finally, there is a dispute, not only political, between the State and the Friuli Venezia Giulia Region in relation to the Zaule regasifier proposed by Gas Natural International and the Snam Rete Gas Pipeline. Both projects received the Environmental Impact Assessment Authorisation from the Ministry of the Environment, but both permits have been challenged by the Friuli Venezia Giulia Region before the Administrative Court of Lazio.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Italy is the third European market for natural gas consumption (approximately 67 billion cubic metres in 2015), with a dependency on imports higher than the European average (approximately 90% with respect to a community average of 70%).

Of the European countries, Italy is the one with the highest dependency on gas, which represents approximately 35% of primary energy consumption and 40% of gross electrical energy production in 2015 (15% and 4% in France, 20% and 17% in Spain, and 23% and 12% in Germany, respectively).

2016 data confirms this picture, with consumption at approximately 71 billion cubic metres in 2016 (+5% from 2015 provisional figures) and a dependency on imports for approximately 92% of gas consumption. Natural gas has not had much of an impact on primary energy consumption, which has remained almost stable, while gross electrical energy production went from 40% to 42% due to the impact of natural gas.

In 2016, despite the reserves still available, domestic gas production went down to approximately five point eight billion cubic metres per year (-14.6% from 2015), covering approximately 8% of consumption, due to the limitations made to offshore operations, the difficulties in operating in a territorial context now generally against such activity, and the complex bureaucratic process connected to regional understandings.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

In 2016, 80.7% of the value of crude oil and natural gas supplies was guaranteed by the leading 10 countries: Russia remained in first place with 23.4%, followed by Algeria with 12.9%, Iraq with 10.7%, Azerbaijan with 10.1%, Libya with 5.9%, Saudi Arabia with 5.8%, Kazakhstan with 4.4%, Kuwait with 3.0%, Iran with 2.5% and the Netherlands with 2.0%.

The shares per country have recorded significant changes over the last year. Of the main supplier countries, Algeria's share went up (+6.7 points), along with that of Kuwait (+2.9 points), Iran (+2.4 points) and Iraq (+1.4 points), whereas the shares of Libya (-3.0 points), Russia (-2.9 points), Qatar (-2.1 points), Azerbaijan (-1.5 points), the Netherlands (-1.3 points) and Angola (-1.0 points) went down. In 2016, Algeria became the second-largest supplier of energy commodities to Italy behind Russia, passing Azerbaijan (which went from second place in 2015 to fourth place in 2016) and Iraq (which remained, as was the case in 2015, in third place).

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

In 2017, export volumes remain unchanged in comparison to past years. The development of transport capacity in the 10-year period (2016–2025) planned by Snam Rete Gas S.p.A. (SNAM) should allow, starting from 2019, export volumes to increase to about five billion cubic metres by 2022.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

There are only modest oil and gas wells in Italy; they are very fragmented and often located at a great depth or offshore. This has made it difficult both to locate and to exploit them.

Italy is the world's 49th-largest oil producer.

The most important oil deposits in Italy are located in mainland and offshore Sicily.

There are also important oil deposits in Val d'Agri, in Basilicata, and in Porto Orsini, in the Ravenna area of the Adriatic.

Exploration for oil is still continuing today, with oil production at around 80,000 barrels per day, while gas production is at approximately 15 billion cubic metres per day. The oil production peak in Italy was reached in 1997, and the current exhaustion speed is 3.1%.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

In the last year, 36% of Italy's energy requirements were met using oil. Hence, it is the primary source for meeting energy demand.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Domestic production represents approximately 7% of Italy's total oil

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consumption; the remaining 93% is therefore imported from abroad. Italian production corresponds to 1% of world production, with the remaining reserves, approximately one billion barrels, representing 0.1% of the world's crude oil reserves.

2.4 To what extent is your jurisdiction's oil production exported?

In 2016, there was an increase in exports of crude oil, semi-processed and finished products, which settled at around 29.7 million tonnes (+5.9% compared with 2015).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Hydrocarbon reserves are owned by the State; their exploration and consequent exploitation are considered in the public interest and are carried out by private enterprises under a legal concession regime (mineral rights).

The general principles that apply to mineral rights are set forth in Royal Decree no. 1443 of 29/07/1927, as amended, *inter alia*, by Law No. 6 of 1957.

In the 90s, the Italian legislator adopted a new national energy plan (Law no. 9 of 09/01/1991) and new provisions for the granting and exercise of licences related to hydrocarbon prospection, exploration and production (Legislative Decree no. 625 of 25/11/1996).

The liberalisation and privatisation process in the energy sector also impacts the oil sector with the Letta Decree and Legislative Decree no. 239 of 23/08/2004 ("Marzano Law").

The environmental aspects are regulated by Legislative Decree no. 152 of 03/04/2006.

The MiSE plays a key role, as through its central and local structures, it assesses projects from a technical and economic standpoint, issues the relevant permits, and supervises the due performance of the works and compliance with safety regulations. The MiSE exercises its functions throughout the useful lifespan of a deposit, from the exploration and production phases until its final shutdown down and clean-up. Applying environmental legislation, the MiSE coordinates its activities with the MATTM and with the Regions, which will assess the environmental compatibility of offshore and onshore extraction projects, respectively.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Mineral rights are made up of prospection and exploration permits, production licences and sole concessions.

Exploration permits are exclusive permits, issued at the request of the oil company, which must submit the exploration programme which it intends to develop and the geological and geophysical studies underlying the choice of the area on the basis of the possible presence of liquid/gas hydrocarbons. Applications may be submitted in competition for the same area by other operators for three months from the publication of the first request in the Official Journal of the European Union.

Exploration permits are issued following a single procedure (lasting a maximum of 180 days) governed by article 1 paragraphs 77 and 79 of Law no. 239 of 23/08/2004, and subsequent amendments.

The project is selected by the MiSE, having obtained the opinion of a consultative organ, the CIRM, which is represented by the competent State administrations (MiSE, MATTM, Ministry of Instruction of University and Research, ISPRA and Avvocatura di Stato) as well as the representatives of the Regions. For offshore permits, the Ministry of Transport and Agricultural and Forestry Policies are involved.

Projects are subject to an environmental screening and/or Environmental Impact Assessment by the MATTM or the Region concerned. Onshore permits are issued by the Ministry in accordance with the Regions concerned.

The involvement of local communities is guaranteed by the role played within the context of the procedure by the Municipal and Provincial administrations concerned, which must express their opinion on the construction of the plants and carry out a check on the compliance of the works with planning regulations.

An exploration permit may last for up to 12 years (six years + possible extensions (maximum extensions of three years each)).

Production licences issued by the MiSE are exclusive ones. In general, the licence-holder, after a positive finding on its part, is granted the right to produce on the basis of a programme for the development of the deposit approved at the time of the granting of the licence.

The surface area of a licence is much smaller than that of an exploration permit, but is not, in general, strictly connected to the deposit found by exploration, as in such area, the licence-holder may also carry out further exploration (geophysical and drilling) to increase the production of the deposits already found.

Onshore production licences are granted by the MiSE in accordance with the Region concerned and once the environmental procedures have been completed.

Production licences have a duration of 20 years, which may be extended by up to a further 10 years.

The sole concession grants the exclusive right to carry out both exploration and production activities and has a duration of 30 years, which may be extended by up to a further 10 years.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Production licences are granted to exploration permit-holders who have found liquid and gas hydrocarbons, and who can show that they have adequate financial and technical resources which allow "good governance" of the deposit.

The Directorial Decree granting the production licence, for which the MiSE is responsible for issuing, contains all the regulations and restrictions established by the bodies which have examined the project during the administrative process of which the Directorial Decree is the last step (the bodies include the MATTM or the Region for environmental compatibility aspects, the Provinces, and the Municipalities for the construction of plants and wells).

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The MiSE also establishes rules in relation to the licence-holder's obligations, facilities and safety which, if not complied with, may lead to the revocation of the licence according to specific procedures laid down by law.

The most important regulations relate to the environmental impact of extraction activities, and the facilities must be operated in compliance with the technical requirements imparted by the competent bodies in the document approving the Environmental Impact Assessment.

The main bodies responsible for checking the environmental area are the ARPA (*Agenzia Regionale per la Protezione dell'Ambiente* – Regional Agency for the Protection of the Environment), which are technical bodies present in every Region of Italy which specifically deal with checking that the chemical and physical parameters of the plants comply with the limit values laid down by environmental legislation (the most important one being Legislative Decree no. 152/2006 and subsequent amendments) and the limits laid down by the licences authorising each specific facility.

The MiSE has a chemical laboratory which carries out checks connected to the workers' health, and on the emissions arising from the treatment of the gas and oil. Should the above parameters be exceeded, in relation, for example, to water discharges or emissions into the air, on the basis of specific provisions of law, the plant operator will incur criminal and administrative sanctions and the closure of the production facility may also be ordered until functioning conditions are returned to below the parameters.

This happened, for example, in the case of the ENI S.p.A. plant in Val d'Agri, Basilicata, which was closed down in 2017 for months in order for environmental safety conditions to be met.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

ENI S.p.A. ("ENI") was the State-owned company in the Italian oil and natural gas industry until the enactment of the Letta Decree, which implemented the principles of Directive 98/30/EC on common rules for the internal natural gas market.

SNAM is the main Italian Transmission System Operator.

Legislative Decree no. 93/2011 implemented the European "Third Energy Package" and established the adoption of the Independent Transmission Operator model, thus requiring a functional separation of SNAM from ENI.

Law Decree no. 1/2012 and DPCM of 25/05/2012 then provided for a full ownership unbundling regime to be implemented by ENI, selling the SNAM's shares.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Licence-holders must comply with works programmes and pay fees in proportion to the surface area covered by mineral rights and royalties, in proportion to the quantity of hydrocarbons produced.

With respect to hydrocarbon exploration and production, the royalties are applied on the basis of the value of production. The royalties for onshore production are currently 10% (7% royalty and 3% to the oil prices reduction fund) if 20,000 tonnes per year are exceeded, while for offshore production they are 7% (4% royalty and 3% safety and environmental share) if they exceed 50,000 tonnes per year for oil, and are applied to the sale value of the quantities produced. Royalties for the production of onshore hydrocarbons are split, as follows: 55% to the Regions; 30% to the State; and 15% to the Municipalities.

However, for the Regions included in Objective 1 (the Regions of southern Italy including Basilicata, the main Italian oil producer), the State's share of 30% is also assigned directly to the Regions. The rate of 3% for offshore permits is paid in full to the State and is 50% allocated to the MATTM to ensure the full performance of the monitoring and fight against sea pollution activities. The remaining 50% is allocated to the MiSE to ensure the full performance of the monitoring activities and safety checks, including environmental ones for offshore exploration and production plants.

Moreover, under Italian law, upstream oil and gas operators are subject to the following tax regime: (i) general corporate income tax (IRES); (ii) regional tax on productive activities (IRAP); and (iii) value-added tax (VAT).

3.6 Are there any restrictions on the export of production?

Under Italian legislation, there are no restrictions on the export of natural gas and/or oil.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are no currency exchange restrictions or restrictions on the transfer of funds derived from production out of Italy.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The transfer of mineral rights is subject to prior authorisation by the MiSE.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

In compliance with the Ministerial Decree of 25/03/2015 and the relative implementing decree of 15/07/2015, mineral rights are granted to applicants which meet the requirements of a general nature, and which possess the technical ability, and economic and organisational capacity in line with the performance and realisation of the programme submitted, with registered office in Italy or in another Member State of the European Union or, upon conditions of reciprocity, in other countries. The applicants must have technical and administrative structures in the European Union adequate for the envisaged activities, or must submit a declaration by which a legal representative undertakes to set them up if the permit is granted.

In order to assess its economic capacity, the applicant must submit a copy of its financial statements for the last three financial years and the turnover for the last three years, and must show that the net equity is higher than zero. Furthermore, certain minimum requirements must be met in relation to the ratio between net debt and net equity.

If the applicant is a physical individual, he must provide, when submitting the application, an initial security deposit of 120,000.00 euros, set up by a bank guarantee or through an insurance guarantee policy, issued by an authorised insurance company duly operating within Italy. They must also submit financial guarantees commensurate with the works programme submitted.

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Mineral rights will not be granted to companies having a fully paid-up share capital of less than 120,000.00 euros, and physical individuals who have not provided the security deposit of 120,000.00 euros.

Should the applicant be a company, the issuance of the permit is subject to the presentation of appropriate bank or insurance guarantees commensurate with the value of the environmental recovery work provided at the time of filing of the relevant application, in the amounts and in the ways laid down by the Decree of 15/07/2015.

Should the applicant be a joint venture, each joint venture party must provide *pro rata* evidence of the bank and insurance policies. This can be provided by only the sole representative for the entire joint venture; however, all the joint venture parties are, in any event, responsible jointly and severally for all the obligations arising under the concession.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The setting up of mortgages on oil fields and gas fields is subject to approval by the MiSE.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Exploration permits and production licences must be preceded by Environmental Impact Assessments for which the MATTM and the competent Region are responsible.

For production licences, the extraction activities must be carried out and the plants must be operated in compliance with the technical regulations laid down by the competent bodies in the document approving the Environmental Impact Assessment.

The main bodies responsible for environmental checks are those described in question 3.3 above.

Furthermore, Legislative Decree no. 145 of 18/08/2015 contains obligations for offshore facilities, and expressly provides that the licence-holder is financially responsible for the prevention and repair of the environmental damage caused by sea operations through hydrocarbon activities carried out by it or on its behalf.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Should a licence-holder wish to decommission physical structures because it intends to shut down a sterile or exhausted deposit or one which can no longer, in any event, be used, or is not capable of further assuring production in commercial quantities, it must ask for authorisation from the UNMIG Section of the MiSE providing details of the shutdown. The licence-holder must draw up a technical report on the shutdown of the deposit, providing details of the actions carried out, and must send it to the competent UNMIG Section. Notice must be given of the shutting down of an onshore deposit to the Region concerned. The competent UNMIG Section must draw up a report on the shutting down of the deposit. In the programmes for exploration, drilling and production activities, the licence-holder must provide details of the necessary actions for the characterisation and possible clean-up of the site for the purposes of its release without any restrictions arising from previous drilling activities. The competent UNMIG Section will certify completion of the shutdown and removal of the physical structures, and will send such certification to the Ministry for the cancellation of the mineral rights. For onshore activities, the programme for the clean-up of the area will be authorised by the UNMIG Section in accordance with the competent Region. At the end of the works, the UNMIG Section will draw up the report that the area has been cleaned up according to the authorised programme and will send a copy of it to the Ministry and to the Region.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

Gas storage is subject to concession. The ways in which the concession is granted are established in Legislative Decree no. 93/2011.

Storage concessions are granted by decree of the MiSE, together with the Region concerned, after an environmental compatibility clearance has been obtained from the administration concerned.

The single procedure for the granting of the concession is structured in various phases which give points to the project on the basis of the following criteria:

a) completeness and rationality of the storage project and the relevant works programme proposed on the basis of geological studies and application of simulation models;

b) planned times for the performance of the works and for full operation in relation to the storage performances provided for in terms of working gas and performance of the delivery and injection point;

c) manner of the performance of the works, with particular regard to safety and environmental protection, and environmental or safety at work certifications;

d) envisaged efficiency of the storage;

e) minimum duration of inflow/outflow;

f) use of original potential of the deposit (ratio between working gas and the original deposit); and

g) ratio between operating costs/working gas.

Points from 0 to 10 are assigned to the project for each of the criteria from a) to c), points from 0 to 5 are assigned for each of the criteria from d) to g), with points for the project equal to the sum from a) to g) for a maximum total of 50 points.

Should the project not reach sufficient quality levels, equal at least to a total of 26 points, it will be rejected, and if there is competition, excluded from the ranking.

If there is a favourable outcome, the decree provides for the limits to be allocated to storage with the relevant shares and guarantee clauses on the attaining of minimum targets as specified in the application; in particular, for working gas.

The decree granting the concession is served on the licence-holder, the MATTM, the Regions and the Municipality are all involved in the process, and is published in the Official Bulletin as well as on the website of the MISE, setting forth the works programme approved and the relevant performance times and, if there is competition, the reasons adopted for the selection. The same decree approves any additional appurtenant actions. The decree shall also be published, by the applicant, in the Official Journal and in a national daily newspaper.

The procedure has an overall maximum duration of 180 days, subject to the times necessary for the compulsory sub-procedures for which other administrations are responsible.

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Concessions for the storage of natural gas shall remain in force for 30 years, which may be extended, no more than once, by another 10 years.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Legislative Decree no. 93/2011 provides that imports under long-term agreements are subject to a MiSE authorisation approving the relevant gas supply agreement, whilst imports under short-term agreements (up to one year of duration) may be carried out subject to a simple communication to be submitted to the MiSE prior to the execution of the relevant gas supply agreement.

Furthermore, according to the MiSE Decree of 19/03/2008, importers from non-EU countries are obliged to offer a certain quota of gas imported to the domestic gas trading market.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Under Italian legislation, oil imports and exports are not subject to any authorisations or communications to any regulatory authority.

However, Italian law provides for certain obligations to be respected, such as maintaining a minimum level of stocks of crude oil and/or petroleum products.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Italy is part of three of the four priority energy corridors included in projects of common interest (PCI) established by the European Commission.

The European Commission has reported on Italy's good performance in terms of energy safety, efficiency, research and innovation, and decarbonisation.

As to safety, despite a high dependency on imports, Italy has the highest degree of diversification of routes and sources of supply in Europe.

Italy's central position for the energy future of the European Union can also be seen from the list of 248 PCIs in the areas of gas, electricity and oil, which include Italian projects involving gas ("Support to the North-Western Market and Trans-Frontier Bidirectional Flows" and "Strengthening for New Imports from the South (Adriatic Line)".

Legislative Decree no. 93 of 01/06/2011 implemented the provisions of European Directive no. 2009/73/EC in Italy. Article 16, as amended by article 26, of Law no. 115 of 29/07/2015 provides that the transportation network operator shall send annually to the AEEGSI and MiSE the 10-year development plan for the network, containing the works necessary to guarantee the adequacy of the system and the safety of supplies, and taking account of the economic efficiency of the investments and protection of the environment.

Article 8 provides that the transportation system operators must have a continuous bidirectional capacity throughout all the trans-frontier interconnections between Member States, including in the connection between Italy and Central Europe, through the Transitgas gas pipeline in Switzerland.

The most important transportation system operator in Italy is SNAM.

The first 10-year plan (2016–2025) presented by SNAM provides for the realisation of the following projects by 2023: "Support to the North Western Market and Trans-Frontier Bidirectional Flows"; "Strengthening for New Imports from the South (Adriatic Line)"; "Interconnection with Slovenia"; and the performance, within a period to be agreed, of the following projects: "Potential Imports from the North-East"; "Further Strengthening of the South"; and the "Galsi Project".

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The transportation of methane gas produced domestically or imported from abroad takes place through the National Gas Pipeline Network (*Rete Nazionale dei Gasdotti* – RNG).

The RNG, as well as transporting gas to interconnection points through the Regional Transportation Network (*Rete Regionale di Trasporto* – RRT), local distribution networks and storage facilities, supplies large industries and thermoelectric power plants.

The legislation on the classification of the RNG is set forth in the Ministerial Decree of 22/12/2000 and subsequent amendments and integrations, while the legislation on the classification of the RRT is set forth in the Ministerial Decree of 29/09/2005 and subsequent amendments and integrations.

Operators of stretches of the RNG and RRT must submit every year to the Ministry, by 31 July, an application for the updating of the networks. As well as a complete list of the existing stretches, the operators must provide a list of any new gas pipelines that have entered into operation, planned ones and finally those shut down as at 30 June of the same year.

By 30 September, the Ministry shall examine the applications and, having obtained the opinion of the AEEGSI and of the Regions concerned, shall publish by 30 November on its website the decree updating the RNG and RTR, which shall enter into force from 1 January of the following year.

The construction of the pipelines and associated infrastructure is subject to a Sole Authorisation under article 52-*quinquies* of Presidential Decree no. 327/2001 (the "Public Expropriation Act"), which replaces any other licence or approval required by law, including Environmental Impact Assessments.

The Environmental Impact Assessment (for which the Ministry of Environment and/or of the competent Region is responsible) is part of the procedure for the issue of the Sole Authorisation.

The Sole Authorisation implies the Declaration of Public Utility of the project and the expropriation constraint.

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6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

If the land is owned by the State, or by the Region or Municipality, the applicant must ask the competent authority for the issuance of a land concession.

Should the land be owned by a private subject, the applicant needs to reach an agreement with the owner to obtain the easement rights for the new pipelines.

However, the issuance of the Sole Authorisation gives the applicant the right to start the expropriation procedures.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

As gas transportation is classified as a public service, owners of pipeline infrastructures and operators of gas transportation and dispatching must grant access to their own network infrastructure to applicants, on a non-discriminatory basis and with the aim of granting the neutrality of gas transportation.

In order to regulate the conditions of access, each network owner/operator is required to adopt its own network code (*Codice di Rete*) on the basis of a standard format approved by the AEEGSI.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The RNG is interconnected to: the RRT; local distribution networks; and storage facilities, and supplies large industries and thermoelectric power plants.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

As gas transportation is classified as a public service, operators must grant access to third parties, provided that they have adequate capacity, and the necessary works are technically and economically feasible (see question 6.4 above).

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

The AEGGSI is responsible for regulating the tariffs for the gas transportation and dispatching service.

The regulation of the tariffs for the natural gas transportation and dispatching service for the regulation period 2014–2017 (RTTG) was approved by Resolution no. 514/2013/R/gas.

By Resolution no. 776/2016/R/gas, AEGGSI approved, in a transitory way and subject to adjustment, the tariffs for the transportation and dispatching service for 2017, while awaiting completion of the procedure started up by Resolution no. 429/2015/R/gas, putting off to a subsequent resolution the method of the aforementioned possible adjustment between the transitory tariffs approved by the same resolution and the tariffs which will be established at the completion of such procedure.

By Resolution no. 776/2016/R/gas, the authority also approved the proposal of the coefficients related to the self-consumption quotas, network leakages and gas not accounted for to be allocated to the users of the services under article 16-*bis* of Resolution no. 137/02 of the AEEGSI.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The natural gas distribution system consists of three different "levels": the legislative level; the regulations level; and the regulatory level.

The legislative level is essentially composed of articles 14, 15 and 16 of the Letta Decree, which identify the general provisions for the gas distribution service. Mention must also be made to article 46-*bis* of Law Decree no. 159/2007, converted into Law no. 222/2007, which required of subsequent ministerial decrees the establishing of uniform tender criteria for the awarding of the service and identification of the minimum territory for the tenders according to optimum territorial catchment areas (*Bacini Ottimali di Utenza* – ATEM), thus superseding the "old" community ambits. With respect to the awarding of the gas distribution system, article 24 of Legislative Decree no. 93/2011 definitively provided that it must take place exclusively through ATEM tenders.

With regard to the regulations level, the following are significant: (a) the Ministerial Decrees of 19/01/2011 and 18/10/2011, which respectively split Italy into 177 ATEMs and identified the individual Municipalities pertaining to each ATEM; (b) the Ministerial Decree of 12/11/2011 (amended recently by the Ministerial Decree of 20/05/2015), which, among other things, laid down the criteria for the assessment of tenders and bids for the awarding of the gas distribution service; (c) the Ministerial Decree of 05/02/2013, which approved the format of the service contract; and (d) the Ministerial Decree of 22/05/2014, which approved the guidelines for the calculation of the reimbursement value for gas distribution systems.

Finally, of no less importance is the regulatory level, made up of a myriad of measures issued by the AEEGSI, of which mention must be made to Resolution no. 113/2013/R/gas (which governs the procedural process for any observations of the authority to be made to the contracting authorities on tender regulations) and Resolution no. 367/2014/R/gas, containing "Tariff Regulations for Gas Distribution and Measurement Services for the Regulatory Period 2014–2019".

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Gas distribution is a "public service activity". The party authorised to grant the distribution service is the local authority, and the service must be awarded exclusively through a tender procedure for periods

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of not more than 12 years. The dealings between the grantor and the concessionaire are governed by service contracts, on the basis of a contract format drawn up by the AEEGSI and approved by the MiSE (see the Ministerial Decree of 05/02/2013).

7.3 How is access to the natural gas distribution network organised?

The tender regulations for the awarding of the gas distribution service are laid down in the Ministerial Decree of 12/11/2011 and subsequent amendments and integrations. This decree, *inter alia*, laid down the rules for the identification of the contracting authority and established its duties. In particular, the contracting authority carries out the tender procedure and awards the contract by delegation of the local authorities (the grantor) and takes care of all dealings with the operator. In this respect, operators must comply with a series of information obligations (of a technical, financial, contractual and tariff nature) with respect to the local authorities (the grantor).

The decree also deals with other significant aspects, such as the calculation of the reimbursement value of the gas distribution system to the outgoing operator, and the way in which the invitation to tender shall be drawn up.

The incoming operator, as well as being entitled to operate the distribution system, will take over the outgoing operator's right to receive a tariff component for the recovery and remuneration of the capital invested by the same outgoing operator to construct the facilities. In this way, the incoming operator is partially compensated for the disbursement made to pay the outgoing operator.

The tender is carried out by adopting a restricted procedure, with the exception of when an outgoing operator manages more than 60% of the redelivery points; in this case, an open procedure is adopted.

The contract will be awarded according to the criterion of the most advantageous economic offer.

Sixty days before publication of the tender documentation, the contracting authority must send the tender regulations to the AEEGSI, together with the guidelines containing minimum development conditions and the justifying note containing any discrepancies from the standard tender regulations. The AEEGSI then has 30 days within which to submit its observations to the contracting authority (otherwise, the silence-consent rule shall apply: see Regulation no. 113/2013/R/gas). The authority's intervention is simply consultative and does not condition the subsequent development of the tender procedure. In fact, any observations of the authority do not bind the contracting authority.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Gas distribution is a public service and, therefore, distributors must allow access to their networks to new operators which are authorised to reach new final users. If the distributor denies access, the AEEGSI will examine the refusal, and in case of unlawful refusal will oblige the operator to grant access.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The tariff system to access the distribution network is regulated by the AEEGSI. The 2014–2019 tariff period was regulated by Resolution no. 367/2014/R/gas.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

There are no limitations on the acquisition of the share capital of natural gas utilities. If the share capital of the distributor company is held by local authorities, private partners have to be selected through a public tender procedure (see question 7.3 above).

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

The sale of natural gas is governed by articles 17 and 18 of the Letta Decree, as amended by article 30 of Legislative Decree no. 93 of 01/06/2011, as well as by the Ministerial Decree of 29/12/2011, which provides for the criteria on the basis of which undertakings are registered in the list of undertakings authorised to sell natural gas to end-customers throughout Italy, consisting of: a) the availability of natural gas and of the modulation service for customers having an annual consumption of not more than 50,000 cubic metres; b) a demonstration of the provenance of the gas and of the reliability of the transportation system; and c) the adequacy of the technical and financial capacities of the undertaking.

There is therefore an accreditation system at the MiSE for the performance of these activities.

From 01/01/2003, sales have been completely liberalised, the classification of "suitability" is extended to all customers, including domestic ones (article 22 paragraph 2 of the Letta Decree) who may freely choose their supplier.

The wholesale market is managed by the Energy Market Operator (*Gestore dei Mercati Energetici*) and exchanges take place on a virtual platform.

Shippers active on the market can purchase natural gas from: private counterparties through exchange platforms; PB-GAS (spot market); or the platform for the balancing out of natural gas.

In order to limit dominant positions, there are maximum market shares. The wholesale market share is limited to a maximum cap of 40% of domestic consumption. If this cap is exceeded, gas release mechanisms are provided for at regulated prices. It is also possible to raise the threshold to 55% if there are undertakings to develop and increase storage capacity by four billion cubic metres over five years.

With regard specifically to retail sales, the AEEGSI supervises the transparency of contractual conditions and service quality, maintaining also the power to fix the tariffs which retailers must offer on the so-called "protected market", together with their offers on the "free market" to end-customers defined as vulnerable.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

In order to balance out the gas market, the party responsible for the balancing, SNAM, carries out sales and purchases on the exchange

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platform for (i) *Title Products*, daily products exchanged on the day before or on the same day, but effective from the time of the transaction up until the gas day, they provide simply for the transfer of title of the quantity of gas being purchased or sold without further specifications, (ii) *Locational Products*, which are those that, in order to keep the market in balance, provide for the modification of the gas flows at a specific entry or exit point starting from a certain time of the gas day, and (iii) *Temporal Products*, which are those which, in order to keep the network in balance, provide for the modification of the gas flows in a certain period of the gas day.

These same methods are regulated by the AEGGSI (see Resolution no. 349/2017/R/gas and Resolution no. 661/2017/R/gas).

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Regasification terminals receive liquid gas transported by ship and transform it into gaseous form. In this way, natural gas can be entered directly into the transportation network.

This is regulated by article 24 of the Letta Decree which: provides for an obligation on undertakings controlling infrastructure essential to the functioning of the gas system, including regasification facilities, to allow access to other undertakings; and governs in an absolute way cases of legitimate refusal to access (refusal of access must be set forth in a reasoned declaration and must be immediately communicated to the AEEGSI, to the Italian Anti-Trust Authority (AGCM), as well as to the MiSE. The AEEGSI shall decide by a reasoned measure in relation to the refusal within three months of such communication).

The construction of regasification terminals involves a very complex authorisation process, of which the main steps include: an Environmental Impact Assessment of the infrastructure project; the performance of Conference of Services (*Conferenza dei Servizi*), which establishes with the local authorities any financial and environmental compensation for the territory on which the facility is to be constructed; and a Sole Authorisation of the construction and operation of the facility by the MiSE.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The construction of regasification terminals is subject to a very complex authorisation procedure, the main steps of which are:

(i) an assessment of the environmental impact of the infrastructure project;

(ii) carrying out Conference of Services – responsible, *inter alia*, for establishing with the local authorities any financial and environmental compensation for the territory on which the facility is to be constructed; and

(iii) Sole Authorisation from the MiSE for the construction and operation of the facility.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The AEEGSI is responsible for approving LNG tariffs. By Resolution no. 438/2013/R/gas, the AEEGSI laid down the criteria for the regulation of the LNG regasification tariffs for the period 2014–2017.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

See question 9.1 above.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Starting from Legislative Decree no. 32 of 11/02/1998, a procedure was started in Italy for the liberalisation of distribution in the oil sector.

The authority responsible for issuing authorisations for fuel distribution facilities is the Municipality in the territory of which the facility is to be found.

Law no. 239/2004 liberalised the production, import, export and storage of mineral oils.

With regards to the discipline of minimum stocks, Legislative Decree no. 249/2012 implemented Directive no. 2009/119/EC, implementing the principles provided for by the Community Law (2009) (Law no. 96/2010).

The State is responsible for the issue of authorisations for the operation of refineries, and the integrated environmental authorisation is required.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Sale of fuel takes place mainly through the distribution network.

The Italian network is made up of approximately 21,000 sales points, and is characterised by being more convenient for consumers but also by having higher system costs.

Of all the facilities of the Italian distribution network:

- approximately 50% are owned by integrated oil companies;
- approximately 32% are owned by non-integrated oil companies which display the brand of integrated oil companies; and
- approximately 18% (therefore, approximately 3,800 sales points) are so-called "*pompe bianche*", which means they display their own brand and obtain supplies independently on the so-called off-network market.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The AEEGSI is responsible for the promotion of competition and efficiency through regulation of the electric energy, gas and water services sector, and the AGCM is responsible for the protection of competition and the market.

Under Legislative Decree no. 93 of 01/06/2011, the dealings between the AEEGSI and the AGCM are based on the principle of loyal cooperation and carried out, in particular, through joint examination procedures, reports and exchanges of information.

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In 2012, these authorities signed a memorandum of understanding to better coordinate their activities to protect the market.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The oil and gas market is not a very competitive market in Italy and is characterised by few players despite the liberalisation process.

In the gas sector, as already stressed in question 8.1 above, the law (i.e. article 3 of Legislative Decree no. 130/2010) has established fixed maximum market shares in order to avoid dominant positions.

Furthermore, an agreement between undertakings to limit competition through price control, distribution of market shares, or within the context of participation in public tenders, for example, in the awarding of a Municipal service for the distribution of gas to end-users, is not allowed.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

If the AGCM ascertains a breach of competition law, it shall order the termination of the infringement.

If the AGCM considers that there has been a serious infringement, it can impose a fine of up to 10% of the worldwide turnover achieved by each undertaking during the previous financial year. The percentage applied will depend on the duration and gravity of the infringement.

AGCM Resolution no. 25152 of 22/10/2015 contains guidelines detailing the criteria for the determination of sanctions in case of antitrust violations.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Merger transactions are under the control of the AGCM.

Law no. 287/1990 ("Antitrust Law") provides that concentrations that are not subject to mandatory filing pursuant to the European Merger Control Regulation must be notified to the AGCM if, as a consequence of the transaction:

- the aggregate turnover realised by the parties to the concentration in Italy exceeds 495 million euros; and
- the aggregate turnover in Italy of the undertaking to be acquired exceeds 50 million euros.

If the above conditions are met, the concentration must be notified to the AGCM before completion (after signing and normally prior to closing, although this is not mandatory), and the purchaser(s) is (are) the entity responsible for the notification filing.

Parties are under the duty to inform the AGCM of a transaction meeting the turnover thresholds, once it has become certain, and such pre-notification phase generally lasts at least two weeks.

As mentioned, once notified, the transaction can, in principle, be completed before clearance by the AGCM is obtained.

After notification has taken place, the AGCM is bound to decide whether to clear the transaction or to open an in-depth investigation within 30 days. This same period can in some exceptional circumstances be extended for a further 30 days.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There are no specific limitations on the entry to the Italian market of foreign companies and capital.

Certain limits may apply in mergers and acquisitions and in participation in tender procedures, if adequate reciprocity guarantees do not exist between Italy and the foreign company's country of origin.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Italian regulatory policy is largely influenced by the implementation of EU legislation.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

The Regional Administrative Courts (at first instance) and the Council of State (at second instance) have jurisdiction over disputes between the operators and the government authorities and regulators.

The Regional Administrative Court of Milan has sole jurisdiction over disputes against AEEGSI resolutions.

It is also important to mention that the AGCM can challenge, before the Regional Administrative Courts, any general administrative acts, regulations and provisions of any public administration (government, local authorities, agencies, etc.) that violate antitrust rules.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Italy has duly ratified both the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the ICSID Convention.

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13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

There are no special difficulties in enforcing judgments or awards against any public authorities (governmental, environmental and/or local authorities).

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

The most frequent disputes in which foreign companies are involved in are related to market trading, tender procedures for distribution contracts, fees and taxes, and there have been cases of judgments in their favour.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

In the last 10 years, Italian legislation in the oil and gas sector has been oriented towards the transition from a monopoly situation to a free market.

It is a slow path that is facing some difficulties. In order to facilitate competition in the market, the Law of 04/08/2017 has foreseen the end of the enhanced protection service in 2019. This mean that the AEEGSI will cease to establish and update every three months the economic conditions (prices) for the supply of electricity and natural gas and protection services for small customers, and end-consumers will have to turn to the free market.

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Fiorella F. Alvino specialises in mergers and acquisitions, and private equity, with additional focus on the energy, oil and gas sectors, and advises developers, lenders and investors from Europe, US, Africa and across Italy on corporate transactions, project finance, mergers and acquisitions, joint ventures and all aspects of investments.

She is the lead partner in energy at the Milan office. She initiated her practice in renewable energy in Milan when this resource was beginning to emerge. She has been involved in private equity ventures in the renewable energy field. Her experience extends also to all regulatory aspects. She has been involved in the provision of legal services on major regulatory, licensing and contractual issues concerning traditional gas and electricity sectors, as well as the area of renewable energy. She has extensive experience in power plant projects, negotiating construction and service agreements, supply and sub-supply agreements.

She collaborates with publications and seminars in the sector, and she is active in associations of law firms dealing with energy matters. Fiorella was named the leading female business lawyer in Italy, based on a survey of women business lawyers and in-house counsel selected by *The Legal 500* and *Chambers and Partners*, both covering national and international firms. She was awarded with a special prize by the magazine *Top Legal* as the best female business lawyer in Italy and nominated by *Who's Who Legal* in 2017, as in the previous years, as one of the leading practitioners in the "Merger & Acquisition", "Corporate Governance" and "Energy" sectors in Italy, following a worldwide survey of clients. In 2011, she also won the "ILO Client Choice Award" in the "General Corporate" sector, given out by the International Law Office (ILO) on the basis of assessments conducted worldwide among in-house lawyers of international companies.

After graduating *cum laude* in law at the University of Milan, she completed the following courses: "Seminar in American Legal Studies" at the Centre for International Legal Studies (Salzburg, Austria); "Orientation Program in US Legal System" at the University of Georgetown (Washington, D.C., USA); and Master of Laws (LL.M.) at Harvard Law School (Cambridge, Massachusetts, USA).

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Giovanna Branca has represented companies operating in the energy sector, assisting them in all regulatory aspects, including applications for licences and permits, providing them with consultancy on a daily basis, as well as advising them on changes in the Italian regulatory system.

She assists clients with basic issues concerning the environmental aspects of land use changes, including clean-up procedures for polluted sites, restoration of unused industrial areas and the establishment of new activities, and waste management.

She assists clients in drafting supply and service contracts, works contracts and agreements among companies for the awarding of public and private tenders, and performs the works and services contracts in compliance with Italian and EU law. She also assists clients in bids for the supply of services and works, and specifically interprets clauses in bid competitions and bid tenders in the context of Italian and EU law.

In the gas sector, she has advised local administrations in drafting bids for the awarding of the natural gas distribution service.

Giovanna is admitted to the Supreme Court of Cassation and High Courts.

After graduating in law at the University of Milan Sacred Heart Catholic University, she completed two post-graduate courses: "Course in EU Rights", approved by the European Commission within the framework of the Schuman programme; and the "University of Milan Advanced Course in Litigation Before the EU Courts".

She contributes to various publications on planning, energy and environmental law.

UGHI E NUNZIANTE
STUDIO LEGALE

Ughi e Nunziante has a long tradition in the energy sector. This goes back to the issue of the first bonds on the international markets by the newly nationalised electricity utility ENEL during the 1960s, and includes important work in the nuclear field up to the discontinuance of nuclear energy in Italy in 1987 and work for oil majors. Over the years, this expertise has been consolidated and expanded.

The Firm has participated in: (i) study and research initiatives organised by "*FEEM-Fondazione Eni Enrico Mattei*" and by the observatory on the administrative regulation of the energy sector managed by the Catholic University of Milan; and (ii) the organisation of seminars dealing with renewable energy.

Our Firm provides assistance in project development and project financing for the design, construction and operation of traditional power plants as well as renewable sources (wind power, solar power, hydroelectric and biomass) power plants. In particular, our Firm drafts and negotiates agreements for the supply, import, sale of transmission capacity and documents addressed to the authorities, such as the Italian Ministry of Economic Development, the National Regulatory Authority for Electricity and Gas and the authorities for the national transmission grid and the electric power market. Our services include dealing with major regulatory, licensing and contractual issues concerning research, extraction and trading of oil, gas and other natural resources.

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Mexico

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Raúl Fernando Romero Fernández

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

According to the National Hydrocarbons Commission (*Comisión Nacional de Hidrocarburos* or "CNH"), the production of natural gas in Mexico, during the first semester of 2017, was approximately 26,094.96 million cubic feet per day ("MMCFD"), which represents a decrease of 4,658.30 MMCFD compared to the figures shown for the same period in 2016. Additionally, it is important to note that most of Mexico's natural gas reserves discovered in 2017 are located in *Campo Akal* (*Cantarell* area), *Region Marina Noreste*, Gulf of Mexico, with a 3P category, and account for approximately 2,181.61 billion cubic feet ("Bcf").

According to the Mexican Ministry of Energy (*Secretaría de Energía* or "SENER"), exports from U.S. pipelines to Mexico will reach 3.8 billion cubic feet per day (Bcf/d) in 2018, which represents more than twice the exports of natural gas from the U.S. to Mexico in 2013 (1.8 Bcf/d). This projected growth is driven mainly by higher demand from Mexico's electric power sector throughout the country.

According to the CNH, in August 2017, *Petroleos Mexicanos* ("Pemex") burned and produced 128.2 MMCFD of natural gas in Mexico. This corresponds to a reduction of 352.4 MMCFD compared to the same month in 2016. To put this into perspective, this reduction represents 9% of the natural gas produced.

Furthermore, it is important to note that a new underwater pipeline running from southern Texas, USA, to Tuxpan, Veracruz, Mexico (along the coast of the Gulf of Mexico) will commence operations in 2018. Please be advised that such pipeline will have a capacity of 2,600 million cubic feet per day ("MMPCD") and an approximate length of 800 kilometres ("km"). This project will contribute to satisfying the natural gas requirements at the Federal Electricity Commission (*Comisión Federal de Electricidad* or "CFE") and will supply natural gas to newly constructed power plants and others that operate with fuel oil, which can be converted to use natural gas.

In July 2017, according to statistics published by the U.S. Energy Information Administration ("EIA"), SENER opened the onshore portion of the Burgos Basin, a shale-rich basin in northeastern Mexico, for natural gas exploration and development by private companies. This is the first time non-state entities were offered access to the Burgos Basin for development since the creation of the national oil company Pemex in 1938.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Currently, Mexico's energy requirements are met through diverse power sources such as natural gas (55%), hydraulic (14.8%), carbon (13%), fuel oil (10%), uranium (3.7%), geothermal (2.3%), wind (0.7%) and solar (less than 0.1% of total production).

Although energy requirements are mainly met through the use of natural gas, statistics show a slight increase in the use of renewable energy sources such as hydraulic and wind power.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

The substitution of natural gas produced from oil for electricity production has grown in 2017, with the main objective of reducing costs and the emission of pollutants, and satisfying the demand for electricity in the country.

According to the Ministry of Energy, from 2015 to 2030, the demand for natural gas will have increased by 20.3%, reaching a volume of 9,030.4 MMCFD. With regards to international trends, it is expected that the demand for electric power will have, from 2015 to 2040, increased by 24.4%, reaching a volume of 32,677.6 MMPCD.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

According to the EIA, in August 2017, U.S. natural gas exports through pipelines to Mexico reached unseen levels, now estimated at almost 4.04 billion MMCFD.

U.S. gas exports are expected to grow further in 2018, due to growing natural gas exports to Mexico and increase in domestic demand.

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2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Pemex has reported that its average oil production in July 2017 was below 2 million barrels per day ("MBD"), the lowest level for a month in more than 20 years. The average production during July 2017 was 1.99 MBD compared to 2.01 MBD in June. According to official statistics, Pemex has estimated that Mexico will produce 1.951 MBD during 2018, lower than 2017.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

In 2015, the demand for fossil fuels at the national level reached a volume of 17,115 MMPCD which represented an increase of 1.7% compared to 2014. Of the total of this demand, natural gas, with a share of 43.8% with a volume of 7,504.1 MMPCD, is followed by gasoline with a participation of 22.3%, diesel with 12.7%, coal with 7.3%, gas L.P. with 6.3%, fuel oil 4.9%, and finally coke of oil with 2.6% participation.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

The largest demand was presented by the public electricity sector with a volume of 3,228.9 MMCFD of natural gas, followed by the oil sector with 2,200 MMPCD, the industrial sector with 1,375.8 MMPCD, and private demand with 568.6 MMCFD. The lowest participation was the residential sector with 94.6 MMPCD, services with 33.7 MMPCD and, finally, the transportation sector with a volume of 2.4 MMPCD.

It is expected that in almost all sectors there will be an increase in demand, with the exception of the oil sector which will decrease by 34% compared to 2015. The electricity sector will continue to be the largest consumer with 58.7% participation; followed by the industrial sectors, with 23.2%; tanker, with 16.1%; residential and services, with 1.3% and 0.6% respectively; and, finally, the motor transport sector with 0.1%.

2.4 To what extent is your jurisdiction's oil production exported?

According to Pemex, Mexico exported, from January 2017 to August 2017, almost 1,099 thousand barrels per day.

Mexico is one of the leading exporters of crude oil worldwide, through its national oil company Pemex (and its subsidiaries).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

With the enactment of the Constitutional Reform in Energy Matters on December 20, 2013 (the "Energy Reform"), a major structural change took place which contributed to the development of the country through the sustainable and efficient use of all natural resources; but above all, it had a high impact on the oil exploration and extraction industry.

All this began thanks to a reform at the constitutional level in which new provisions on energy were added.

One of the major advances of the Energy Reform has been in natural gas, particularly in the extraction and exploration of natural gas, with the introduction of Round Zero, Round One and Round Two. Round One is the first international public tender for the exploration and extraction of hydrocarbons in the history of Mexico.

Derived from the above, various provisions were published in the Official Gazette of the Federation, specifying the requirements for treatment and refining permits for oil, natural gas processing, as well as matters involving the transportation, storage, distribution and commercialisation of natural gas, in order to generate a market that is more competitive and somehow more efficient.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

There are many types of exploration and extraction contracts that may be tendered by and executed with the CNH, but the contract to be awarded is previously decided by SENER. The contracts are: (i) services; (ii) profit sharing; (iii) production sharing; (iv) licence; and (v) any other contract resulting from the combination of the foregoing. By law, mineral rights of oil and natural gas shall remain state property.

Under Mexican law, a licence contract gives partial ownership and possession to the contractor in exchange for the payment of taxes to the Mexican government. Finally, profit-sharing and service contracts do not give title or possession to the contractor of the hydrocarbons, only cash considerations.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

In accordance with the CNH, all contractors that want to obtain exploration and extraction contracts, must carry out all operations plans as approved by the CNH. Also, the execution of any contract must include investment and several pieces of information depending on the block they want to operate in.

As mentioned in the answer to question 3.2 above, there are five different types of exploration and extraction contracts that have to be approved and executed with the CNH: (i) services; (ii) profit sharing; (iii) production sharing; (iv) licence; and (v) any other contract depending on the combination of the foregoing.

Once the contract has been approved, the contractor has several obligations to carry out during the entire duration of the contract. Moreover, the amount of the work commitment would vary depending on the size and type of the fields that they will work with.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

According to the Mexican Constitution, oil and solid, liquid or

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gaseous hydrocarbons in Mexican subsoil are the inalienable and indefeasible property of the nation and no concessions will be granted. The purpose of this is to provide income for the state which will contribute to the long-term development of the nation, and provide income for the exploration and extraction of oil and other assignments of the productive enterprises of the state or through contracts with them or with individuals, in the terms of the Regulatory Law.

In 2014, the CNH stated in Round Zero that Pemex has to carry out its exploration and extraction plan in compliance with several contracts.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

In general, contractors under exploration and extraction contracts must pay: (i) a royalty that is a percentage of the gross revenues of the production; (ii) an exploration fee per square kilometre of the block during the exploration phase of the contract; (iii) a percentage of the profit oil or additional percentage of the production depending on the type of contract; and (iv) income tax applicable to the profits obtained from hydrocarbons production.

3.6 Are there any restrictions on the export of production?

As for service contracts and profit-sharing contracts, oil and gas production is transferred to a special State Trader ("*Comercializador del Estado"*) as an intermediate, who will sell and then distribute the proceeds from the sale to: (i) the Mexican Fund for Stability and Development; and (ii) the contractor, once its commission fee has been charged.

On the other hand, for production-sharing contracts and licence contracts, the contractor is free to store or sell the production it owns to national or international markets, subject to the regulatory permits set forth by the Energy Regulatory Commission (*Comisión Reguladora de Energía* or "CRE").

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Under the current legislation, there are no currency exchange restrictions or direct transfer fund restrictions. Notwithstanding the above, depending on the type of contract under which hydrocarbons are produced, contractors may not be able to market the production directly, but only through a special State Trader, which may indirectly limit currency exchange options available to monetise production.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Pursuant to the Hydrocarbons Law and the model contracts of the corresponding Round Bidding Guidelines, transfer of rights or interests shall not be permitted unless authorised by the CNH. The CNH will consider the same criteria for the prequalification process of the bid. Additionally, no change of control, either direct or indirect, shall exist without the previous consent of the CNH.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

As part of the formal bid proposal, bidders have to present a seriousness guarantee that shall be executed by the CNH in case a bidder wins a block in a bidding round but does not sign the corresponding contract. Once the winner of the bid executes the exploration and extraction contract with the CNH, such participant shall submit one Corporate Guarantee plus an additional Performance Guarantee to comply with the minimum work commitment. The Corporate Guarantee shall be submitted by the ultimate parent of the winning bidder that obliges jointly and severally with such bidder.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Article 45 of the Hydrocarbons Law provides that contractors and assignees are allowed to report, for accounting and financial purposes, all the benefits of the exploration and extraction contracts or assignations, as long as such assignation or contract sets forth that mineral rights are owned by the state.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

The Hydrocarbons Law sets forth the need for a social impact authorisation issued by SENER for the development of a hydrocarbons project. It is noteworthy to mention that rights of way obtained for the development of hydrocarbon blocks are subject to a special acquisition process, which involves both executive and judicial authorities.

The National Agency for Industrial Safety and Environmental Protection for the Hydrocarbons Sector (*Agencia Nacional de Seguridad Industrial y de Protección al Medio Ambiente del Sector Hidrocarburos* or "ASEA") regulates and supervises environmental protection, and health and safety.

The ASEA's health and safety provisions, which are applicable for activities related to hydrocarbons, are still pending publication. Also, Mexican law establishes that any person involved in the development of any oil and gas activity has to obtain an environmental impact authorisation, granted by Ministry of Environmental and Natural Resources (*Secretaría de Medio Ambiente y Recursos Naturales* or "SEMARNAT").

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

The ASEA Law sets out provisions for the abandonment or decommissioning of this kind of structure used in oil and natural gas.

Furthermore, the model contract used in Round One has a specific provision that requires the contractor to set an abandonment trust, which shall be controlled jointly by the contractor and the CNH, in case a commercial discovery exists.

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3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/ requirements of the legislation?

Pursuant to the Hydrocarbons Law, gas storage services, as a general rule, are subject to non-discriminatory third parties open access in exchange of a tariff payment approved by the CRE. A certain percentage of the storage capacity may be available for self-use, subject to prior authorisation by the CRE.

Despite the above, it is essential to highlight that, as of August 28, 2014, the creation of the National Center of Natural Gas Control (hereinafter referred as "CENAGAS") was decreed with the purpose of generating a competitive natural gas transportation and storage market. This centre will also act as an independent operator of the Integrated National Natural Gas Transportation and Storage System, which is meant to maintain the continuity and safety of the supply of natural gas across Mexican territory.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

According to Mexican regulations, contractors carrying out regulated activities and cross-border sales and deliveries, in relation to exportation activities, have to obtain a permit issued by SENER, an authorisation from the Tax Authorities is also needed, and for a marketing permit an authorisation is required from the CRE.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Following the Energy Reform and with the entry into force of the Hydrocarbons Law, the legal framework that has governed the development of the hydrocarbons and oil industry in the country was profoundly modified so that Mexico can achieve important energy goals and a new market structure.

Pursuant to article 48 of the Hydrocarbons Law, the export and import of hydrocarbons shall be subject to a permit granted by the Ministry of Energy. As for service contracts and profit-sharing contracts, oil and gas production is transferred to a special State Trader, an intermediary, which will distribute any proceeds from the sale to (i) the Mexican Fund for Stability and Development, and (ii) the contractor, once its commission fee has been charged.

On the other hand, for production-sharing contracts and licence contracts, the contractor is free to store or sell the production it owns to national or international markets, subject to the regulatory permits set forth by the CRE.

For sale of oil in Mexico, the contractors must obtain a permit issued by the CRE, and several Tax authorisations are required.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

According to the Hydrocarbons Law, transportation of oil and gas through discharge lines (from upstream production points to the point of entry into the transmission network) are considered collection activities (*Recolección*), which are regulated by the CNH. However, such governmental entity has not issued any regulations related to hydrocarbons collection activities.

As of today, only Pemex owns hydrocarbons collection facilities, given that prior to the enactment of the Energy Reform it was the only entity authorised to carry out E&P activities in Mexico.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

Notwithstanding that the Hydrocarbons Law does not require obtaining any permits to carry out collection activities, new regulations to be published by the CNH may include further provisions in this respect.

Regardless of future regulations issued by the CNH, the construction and operation of collection pipelines would also require other federal, state or municipal permits and authorisations, including those related to environmental impact, land use and archaeological site protection.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

The hydrocarbons industry is of public interest and exclusive federal jurisdiction; therefore, only the federal government may stipulate the applicable standards for land regulation related to the sector's activities.

The Hydrocarbons Law contemplates certain procedures for acquiring land and/or rights of way for hydrocarbons projects that facilitate land access and/or land use in coordination with both executive and judicial authorities.

Furthermore, in case an agreement between the project developers and landowners is not possible, governmental authorities can enforce compulsory acquisition to grant land access through legal easements.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

The CNH has not published applicable regulations to gathering activities. It is plausible that this service will be subject to open access obligations for third parties with open seasons to award the system's available capacity in a non-discriminatory way, as it works with transmission, storage and distribution services.

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6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Before the Energy Reform, Pemex was the only oil and gas producer in Mexico and the only operator of gathering pipelines. Much of the information regarding these type of pipelines is not available to the public; however, the pending regulations of these activities by the CNH will probably provide cooperation and coordination mechanisms as they do in the case of natural gas transmission, storage and distribution.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Natural gas transportation/collection regulations are pending publication by the CNH, but they will probably function in an analogous way to those applicable to transmission, storage and distribution.

In general for other activities, permit-holders, who provide transportation and distribution services to third parties through pipelines, as well as hydrocarbons storage services, have the obligation to provide open and not unduly discriminatory access to their facilities and services, subject to the availability of their systems. If there is no available capacity, permit-holders may execute agreements with third parties in order to expand or extend their systems. Open seasons may also be carried out in order to determine the expansion and/or extension requirements as well as the investment scheme. The users of such system shall pay interconnection costs.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

The Terms and Conditions of each permit-holder may be negotiated between the parties and can include certain provisions or special conditions, subject to the approved Terms and Conditions for the Transportation Services, and subject to approval from the CRE.

Furthermore, CRE shall approve a maximum tariff to be charged for the transportation of natural gas.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The Hydrocarbons Law provides the regulations for natural gas transmission and distribution activities, the authority in charge of granting permits for this activity is the CRE. The CRE also approves the applicable tariffs for the distribution services.

The distribution permits the CRE grants depends on the specific geographic zone, taking into account the technical and economic requirements that allow the development of the distribution network.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Once the CRE grants the distribution permit, the permit-holder must also obtain: (i) a construction and land use authorisation granted by the local and municipal authorities; (ii) a property or possession title; (iii) an environmental impact authorisation with a risk study issued by the ASEA; and (iv) an archaeological authorisation issued by the Anthropology and History National Institute. In addition, the permit-holder may also require road crossing authorisations and electricity transmission line crossing authorisations, and other permits and authorisations.

7.3 How is access to the natural gas distribution network organised?

The natural gas distribution network is divided into geographic zones allotted across the country and assigned by the CRE either to exclusive permit-holders, or if it is not a first-time assigned zone, to different permit-holders that may carry out the activity within such geographic zone. Currently, there are 15 geographic zones and approximately 24 granted permits. Subject to the applicable regulations, open access shall be granted to users that require distribution services.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Distributors are obliged by law to extend or expand their systems within their geographic zone. Furthermore, natural gas distribution companies shall develop an expansion plan in order to connect new users to their system.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The fee that is charged to users of the distribution network is determined by the CRE for each permit-holder.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

There are no restrictions or limitations in relation to acquiring an interest in a gas utility or the transfer of assets forming part of the distribution network. However, certain notifications shall be given to the CRE and, depending on each case, permits for modifications may have to be approved by such Commission.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

The Hydrocarbons Law established that natural gas trading activities

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are selected as regulated activities, and for this activity one must obtain a commercialisation permit issued by the CRE. Article 27 of the Mexican Constitution sets forth that the state is the owner of all the hydrocarbons situated in Mexican subsoil.

Natural gas extracted under a profit-sharing contract will all be traded through a State Trader hired by the CNH, while natural gas extracted under a licence contract will be owned and freely traded by the contractor, but shall require a permit by the CRE to trade in Mexican territory or to export natural gas. In the production-sharing contract the state will trade by its own State Trader in its proportion of natural gas and the proportion that corresponds to the contractor, the latter will be traded by such contractor, in case of licence contracts.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas commodities can be traded by individuals or entities, only within the requirements provided by law; this includes bundled products and services.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Transportation through pipelines and storage of Liquefied Natural Gas ("LNG") is considered a regulated subject matter under Mexican regulation. Also, storage of LNG has been a regulated activity since the Energy Reform.

Furthermore, liquefaction, regasification, compression and descompression of natural gas, under the new regime of the Hydrocarbons Law, all require a permit granted by the CRE. The joint or separate performance of these activities shall be subject to certain general provisions the CRE has yet to issue.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Notwithstanding, the fact that certain regulatory provisions applicable to LNG plants are still pending, the construction and operation of an LNG plant will require a regulatory permit by the CRE, as well as other relevant permits required for any energy project such as a social impact authorisation, an environmental impact authorisation, and local construction licences.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The services required for the LNG sector are regulated by CRE not only in terms of their performance, but in terms of the consideration or tariff that is charged for the rendering of such services.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Currently, only the storage of LNG is subject to an open access obligation towards third parties. For such purposes, permit-holders are required to carry out open season procedures in order to accommodate the requests of interested third parties.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The Hydrocarbons Law established that all commercialisation permits, transportation, storage, distribution and open access to pipelines and facilities, use of own transport and storage, and authorisation of managers' measurements are granted by the CRE. Moreover, oil and gas, petrochemicals, or refined products trading require the commercialisation permit from the CRE. SENER is in charge of oil refining and natural gas processing activities.

Notwithstanding the above, oil products that are traded by individuals are not subject to regulated prices, but oil products that Pemex trade are subject to the terms of the first-hand sales approved by the CRE.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Pemex and its subsidiaries may trade oil and gas extracted by means of their assignation titles.

Additionally, contractors under certain hydrocarbons exploration and extraction contracts (namely, licence contracts and production-sharing contracts) may trade oil and gas extracted from their fields on their own. Otherwise, oil and gas are traded through the State Trader which, until December 31, 2017, shall be Pemex.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The Federal Economic Competition Commission ("COFECE") is, in general, the authority in charge of regulating competition and anti-trust practices in Mexico. Nevertheless, the CRE, with the opinion of the COFECE, shall issue certain administrative provisions that apply to regulated activities of the hydrocarbons sector in order to promote the efficient development of competitive markets.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The Federal Antitrust Law in Mexico regulates different anticompetitive practices such as absolute monopolistic practices, relative monopolistic practices, illicit economic concentrations and any other restriction being imposed on the market. The COFECE is entitled to regulate any economic activity performed by any economic agent; therefore, its scope is of general applicability in the country.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

In 2014, with The Federal Antitrust Law, the COFECE has new powers to eliminate barriers to competition, regulate access to essential inputs and order the divestiture of assets, if the case requires so, to restore competition conditions.

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It works as a jurisdictional entity for the sanctioning of anticompetitive practices, which consists of different stages, such as: investigation; evidence analysis; service of process; and trial resolution.

Additionally, the CRE is invested by the Hydrocarbons Law with power to apply penalties to permit-holders that do not adhere to the economic competition provision that such authority issues.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

In Mexican regulations, there are concentrations that can be defined as merger, acquisition of control, or any act involving companies, associations, shares, social parties, trusts or assets, in general, which is to be made between competitors, suppliers, customers and/or other economic agents which are regulated by the Federal Competitions Law. Transactions which qualify as concentrations are:

(i) Any acts that represent an amount equal to or greater than 18 million minimum wages in Mexico (USD$70 million).

(ii) Any acquisition of more than 35% of the capital stock of a company with total sales or assets in Mexico equal or greater than 18 million minimum wages in Mexico.

(iii) Any acts resulting in the accumulation of more than 8.4 million minimum wages in Mexico (approximately USD$33 million) in assets or stock, with the participation of economic agents that have, jointly or separately, sales or assets in Mexico with a value greater than 84 million minimum wages in Mexico (USD$187 million).

Any of the abovementioned transactions must be approved by the COFECE, and the notification of concentration must be made to such authority.

The COFECE must verify that the transaction does not violate any free competition principles or the law.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There are no restrictions or limitations for foreign companies due to the recent amendments to the Foreign Investment Law.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Mexico has entered into and ratified an international agreement with the United States of America related to cross-border hydrocarbon deposits in the Gulf of Mexico. This instrument sets forth collaboration measures between these two countries for certain offshore oil and gas reserves shared by these two countries. Mexico is not a part of a multinational arrangement, such as OPEC.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

The model exploration and extraction contracts published by the CNH include some provisions regarding arbitration in accordance with the UNCITRAL rules for most disputes. An exception to arbitration in this type of contract is the provision for contract rescission by administrative authorities, which may be exercised if a rescission event arises.

For the purposes of an arbitration, the applicable law shall be Mexican Law, the arbitration procedure shall be held in Spanish language, the arbitration site shall be The Hague in the Netherlands, and the award shall be binding for both parties. Additionally, with regard to private contracts in regulated activities, the regulatory entities, such as the National Hydrocarbons Commission and the Energy Regulatory Commission, might be appointed as arbitrators for dispute resolution.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Mexico is part of the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, without any reservation whatsoever, and has been since 1971; however, Mexico is not a member of the Convention on the Settlement of Investment Disputes between States and Nationals of Other States.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

It is not as common as it might be in other countries, though it is a practical issue, not a matter of law. The Commerce Code establishes in its Section IV of Title V, the applicable rules for arbitration agreements between the parties. Such Code prescribes that the award must be enforceable through Mexican jurisdiction authorities, regardless of the country in which the award was issued.

Notwithstanding the aforementioned, Mexican judges are entitled by law to review the award and decide whether it complies with the provisions of Mexican law, with the possibility of a judicial revision to have final arbitration resolutions.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

There have been few cases in which international judgments have

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been resolved in favour of foreign companies against governmental authorities, as in the case between Pemex, a state-owned company, and Kellogg, Brown & Root ("KBR") in which KBR was granted an award of USD$465 million for terminating a contract in 2004. Pemex's new legal organisation could lead to a more effective and efficient path for dispute resolution between a state-owned company and a private company.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

The years 2015, 2016, and 2017 have been exciting for the oil and gas sectors in Mexico. The constitutional, legal and regulatory changes that derived from the Energy Reform have brought major investment in different sectors related to the energy industry in the country.

In accordance with the above, it is expected that in 2018 several major private brands will open their own gasoline stations throughout the country.

Furthermore, the CNH has announced the commencement of Round 3.1 for the awarding of new E&E onshore contracts. It will still take some time for hydrocarbons to be actually produced from these awarded blocks; however, it is a huge step to creating a competitive hydrocarbons extraction industry in Mexico.

Mexico's recent reforms in different sectors are fostering a culture of compliance. An anti-corruption legal framework is being implemented through the General Law of Administrative Responsibilities, the General Law of the National Anti-corruption System and the Law of the Federal Court of Administrative Justice. Following the momentum set by these laws, Pemex and other state- and privately-owned companies have taken steps to create or adapt their conduct and ethical codes.

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Jesús Rodríguez Dávalos, founding member and Managing Partner of RDA since 1995, positioned RDA as a trending energy/infrastructure and consulting firm focused on the power, oil and gas sectors. His experience in strategic legal, business development and cross-cultural matters has allowed him to identify opportunities on behalf of his clients. He has led many first-of-a-kind projects: the first cross-border wet gas pipeline; the first CNG project; the regulatory strategy of the first ethane pipeline; and the only three private LPG pipelines in operation, among others. He was leading legal counsel of "*Los Ramones*" in its three phases. He has represented natural gas distribution companies since 1995; since 2000, he has advised independent power generation companies (IPP, Cogen plants and renewable energy projects) in Mexico and in Central America, representing more than 5,000 MW of installed capacity. He represents: more than 16 E&P Blocks; right of way acquisition of over 5,500 km for pipeline and transmission lines; more than 2,500 gasoline retail stations; an LNG facility in the Gulf of Mexico; and product refining terminals. Mr. Rodriguez and his team recently worked with Pemex to obtain permits and regulated tariffs for eight transportation systems for oil, refined products and petrochemicals, as well as those for 77 petrochemical and oil product storage facilities.

Raúl Fernando Romero Fernández
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Raúl Fernando Romero Fernández, Senior Associate at RDA, has participated in strategic projects on distribution, transportation and storage of hydrocarbons. He successfully developed and negotiated the agreements of the First Operative Natural Gas SWAP in Mexico, as well as the customs strategy. Mr. Romero developed and negotiated contracts for the first private ethane pipeline in Mexico. He also had an outstanding participation in the execution of TSA, O&M and EPC and in the general contractual scheme of all three phases of the "*Los Ramones*" pipeline and Transoceanic Project. He played a key role in the negotiation and preparation of incentivised agreements and hydrocarbon purchase agreements. He recently had an outstanding participation in the regulatory and legal strategy of the first private terminal of refined products in Mexico.

He has successfully executed NAESB agreements for power generating companies and independent power producers (natural gas distributors and industrial clients) in Mexico. Mr. Romero has developed and executed contracts of regulated activities for power generating projects such as combined cycle and Cogen projects. He has led companies on bidding processes before CFE, the Federal District government and Pemex.

RDA RODRÍGUEZ DÁVALOS ABOGADOS

Rodríguez Dávalos Abogados ("RDA") is a specialised law firm with more than 20 years of accumulated experience, and with national and international regulatory and commercial expertise in the energy industry. RDA has highly skilled attorneys and consultants with practice not only in the Oil, Gas, and Power Industries, but also in Corporate Law, Mergers and Acquisitions, Banking, Finance, Foreign Investment, Procurement, Government Contracts and Public Works, Commercial Matters, Industrial Property and Rights of Way ("ROW"). The firm's overall projects represent national and foreign investments of over USD$5.5 billion.

RDA has a very substantial and proven record in infrastructure projects (natural gas, LPG, LNG, crude oil E&P, basic petrochemicals, sulphur, gas and liquids transportation pipelines, fuel management projects and business development, cross-border transactions, finance and credit facilities, guarantees, risk management mechanisms and techniques, Mexican, U.S., and international industry standards and best practices, purchase and sale agreements, transportation, storage, and exchange agreements, maritime trade agreements, and corporate governance, administration and counselling). RDA is skilful in completing agreements with the Energy Regulatory Commission ("CRE"), *Petróleos Mexicanos* ("Pemex") and its subsidiaries, the Ministry of Energy, and the Federal Electricity Commission ("CFE"), in all stages: (i) planning; (ii) development; (iii) negotiation; (iv) operation; and (v) management.

RDA is deeply engaged in offering value-added and integrated services to our clients to successfully achieve and develop projects as well as in rendering the most-qualified representation.

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Moldova

Andrian Guzun

Schoenherr

Bernd Rajal

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In 2016, natural gas for the Moldovan market was predominantly acquired from the Russian company P.A.O. Gazprom (*Gazprom*) – 1,037.2 million cubic metres out of a total volume of 1,038.4 million cubic metres. Also, 1.2 million cubic metres of natural gas have been acquired from the Romanian company OMV Petrom S.A. The local production of natural gas was insignificant – only 0.1 million cubic metres (from Cantemir county, in the southern part of the Republic of Moldova (*Moldova*)) (http://anre.md/files/raport/Raport%20anual%20de%20activitate_2016.pdf).

Pursuant to the data published by the National Agency for Energy Regulation (*NARE*) (http://anre.md/ro/content/lista-titularilor-de-licen%C5%A3%C4%83), NARE issued two licences for the transportation of natural gas, 13 licences for the supply of natural gas at regulated tariffs, 25 licences for the distribution of natural gas, six licences for the supply of natural gas at non-regulated tariffs (by means of compressed natural gas stations) and two licences for the supply of natural gas at non-regulated tariffs (by means of the gas network).

The main player on the Moldovan natural gas market is Moldovagaz S.A. (*MG*): an entity under the ownership of Gazprom (50%), Moldova (35.33%), the Committee of Management of the Property of Transnistria (13.44%) and its staff (1.23%); and a supplier of natural gas, which *inter alia*:

(a) concluded the agreement with Gazprom on the supply of natural gas (i.e. for the entire volume of imported natural gas of 1,037.2 million cubic metres (more than 99.8% of the entire volume of acquired natural gas));

(b) is the founder (sole shareholder) of 12 main natural gas distribution system operators (*DSOs*). Pursuant to the reports of the DSOs, the total length of the natural gas network of such operators is 21,750.50 km (http://anre.md/files/raport/Raport%20anual%20de%20activitate_2016.pdf); and

(c) is the founder (sole shareholder) of Moldovatransgaz SRL (*MTG*) – the main Moldovan transport system operator (*TSO*), which, *inter alia*, ensures the transit of gas on Moldova's territory through trunk pipelines to the underground storage facility in Bohorodchany (Ukraine) and the Balkan region. The activity of the transportation of natural gas of MTG is performed through its transmission network (including magistral pipelines, with a total length of 656.25 km, and pipeline branches, with a total length of 903.42 km) (http://www.moldovatransgaz.md/menu/ru/transportation-services/technical-and-economic-indicators).

The Government of Moldova (*GoM*) is aware of the fact that in order to ensure a secured supply of natural gas, it has to take certain measures: diversification of the supply sources (including identification of local sources); implementation of LNG-related projects; and building of natural gas storage facilities (Government Decision no. 102 dated 5 February 2013 "On the Energy Strategy of the Republic of Moldova until 2030").

In this context, in 2014, a new TSO was established: I.S. Vestmoldtransgaz (*VMTG*), a state-owned company which is to operate the Iasi (Romania) – Ungheni (Moldova) gas interconnector (with a total length of 43.2 km) and the projected Ungheni–Chisinau natural gas pipeline. On 27 October 2017, VMTG was put on sale by the Moldovan Public Property Agency. The tender book (with regard to such sale) provides for the obligation of the potential buyer to invest up to EUR 93 million in the first two years after the acquisition (Official Gazette of the Republic of Moldova no. 371-382 dated 27 October 2017).

Further, on 30 December 2016, the GoM issued a decision approving the results of a tender on selection of an entity, which is to perform works on the geological exploration of hydrocarbons on the territory of Moldova. Frontera Resources International LLC was designated as the winner of such tender: it obtained the right to perform such works on geological exploration; and the right of further exploitation (Government Decision no. 1439 dated 30 December 2016) (pursuant to certain sources, on a territory of *cca.* 12,000 km^2).

We are not aware of any current LNG-related projects in place in Moldova; LNG is currently not traded in Moldova. Also, there are no (underground) storages of natural gas on the territory of Moldova (http://www.infoeuropa.md/files/analiza-tematica-privind-prevederile-acordului-de-asociere-rm-ue-in-sectorul-energetic-gaze-naturale-si-energie-electrica.pdf).

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

In 2016, the total gross consumption of energy in Moldova was 2,796 Mtoe, out of which the consumption of natural gas constituted 838 Mtoe (*cca.* 30%), coal constituted 75 Mtoe (*cca.* 2.6%), petroleum products constituted 895 Mtoe (*cca.* 32%), bio-fuel and waste

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constituted 698 Mtoe (*cca.* 25%), and electric energy constituted 290 Mtoe (*cca.* 10.4%) (http://www.statistica.md/public/files/publicatii_electronice/balanta_energetica/BE_2017_rom.pdf).

Although the total gross consumption of energy in Moldova increased during the period 2010–2016 (2,633 Mtoe in 2010, 2,643 Mtoe in 2013 and 2,796 Mtoe in 2016), the share of natural gas in such consumption continuously decreased (*cca.* 36.5% in 2010, *cca.* 31.5% in 2013 and *cca.* 29.9% in 2016).

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Pursuant to the Energy Balance of Moldova for 2016, the entire volume of 838 Mtoe of natural gas consumed in Moldova was imported (http://www.statistica.md/public/files/publicatii_electronice/balanta_energetica/BE_2017_rom.pdf).

The Activity Report of NARE for 2016 indicates that *cca.* 0.1 million cubic metres of natural gas represents the volume of natural gas produced in Moldova (from Cantemir county, in the southern part of Moldova) (http://anre.md/files/raport/Raport%20anual%20de%20activitate_2016.pdf).

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Moldova does not export natural gas.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Pursuant to the Activity Report of NARE for 2016 (http://anre.md/files/raport/Raport%20anual%20de%20activitate_2016.pdf), the consumption of oil products in Moldova is mainly ensured by imported petroleum products. In particular, the volume of imported main petroleum products in 2016 constituted *cca.* 542,523 to 788,908 tons of Diesel, *cca.* 169,418 tons of Gasoline and *cca.* 76,967 tons of Liquified Petroluem Gas (*LPG*).

The main supplier of petroleum products to Moldova is Romania (with a share of 89.1% for Diesel and 70.4% for Gasoline). Other suppliers of petroleum products worth mentioning are the Russian Federation (16.4% for Diesel), Belarus (6.7% for Gasoline and 4.7% for Diesel), Bulgaria (4.3% for Diesel), Lithuania (2.9% for Diesel and 2.9% for Gasoline) and Israel (1.1% for Diesel). The LPG is mainly imported from the following countries: the Russian Federation (55.6%); Romania (34%); Kazakhstan (7.8%); and Belarus (2%).

Further, pursuant to the Energy Balance of Moldova for 2016, a volume of only 7 Mtoe of petroleum products is ensured by means of primary production.

Pursuant to the data published by NARE (http://anre.md/ro/content/titulari-de-licen%C5%A3%C4%83-0), 33 licences have been issued for the import and wholesale of Diesel and Gasoline, 11 licences for the import and wholesale of LPG, 86 licences for the retail of Diesel and Gasoline by means of fuel stations, and 75 licences for the retail of LPG by means of fuel stations.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

In 2016, the total gross consumption of energy in Moldova was 2,796 Mtoe, out of which the consumption of petroleum products constituted 895 Mtoe (*cca.* 32%) (http://www.statistica.md/public/files/publicatii_electronice/balanta_energetica/BE_2017_rom.pdf).

The volume of petroleum products consumed in Moldova, as well as the share of petroleum products in the total gross consumption of energy in Moldova, have continuously increased during the period 2010–2016 (776 Mtoe (*cca.* 29.4%) in 2010, 785 Mtoe (*cca.* 29.7%) in 2013 and 896 Mtoe (*cca.* 32%) in 2016).

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Pursuant to the Energy Balance of Moldova for 2016 (http://www.statistica.md/public/files/publicatii_electronice/balanta_energetica/BE_2017_rom.pdf), in 2016, 920 Mtoe of petroleum products have been imported, whereas the volume of petroleum products primarily produced in Moldova was only 7 Mtoe.

2.4 To what extent is your jurisdiction's oil production exported?

Pursuant to the Energy Balance of Moldova for 2016 (http://www.statistica.md/public/files/publicatii_electronice/balanta_energetica/BE_2017_rom.pdf), in 2016, the volume of exported petroleum products was 15 Mtoe.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The main legal framework in the domain of exploration and extraction of natural resources, including oil and natural gas, on the territory of Moldova is constituted of Natural Resources Code no. 3 dated 2 February 2009 (*Ro. Codul Subsolului*) (*CS*), Law of the Republic of Moldova no. 534 dated 13 July 1995 "On Concessions" (*Ro. Legea cu privire la concesiuni*) (*Concessions Law*) and Law of the Republic of Moldova no. 179 dated 10 July 2008 "On Public-Private Partnerships" (*Ro. Legea cu privire la parteneriatul public-privat*) (*PPP Law*). Certain rules with regard to the production of natural gas are stipulated by Natural Gas Law no. 108 dated 27 May 2016 (*Natural Gas Law*).

The most important rules and principles on the exploration and extraction of natural resources, including oil and natural gas, on the territory of Moldova are, as follows:

(a) all the subsoil resources (including oil and natural gas) constitute the public property of the state;

(b) the subsoil sectors cannot be alienated – only transferred into use;

(c) the period of extraction of subsoil resources depends on the period of operation of the mine field, in accordance with the approved technological documentation;

(d) generally, a right of use over a sector of subsoil (including for the exploration and extraction of oil and/or natural gas) appears on the basis of:

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- a decision of the GoM, as result of the tender for the exploration and extraction of mineral resources; and
- a concession agreement;

(e) the concession agreement is concluded between the user (investor) and the Ministry of Agriculture, Regional Development and Environment (*MARDE*), and contains the conditions of use of the conceded subsoil sectors;

(f) the activity of producing natural gas requires a licence issued by NARE; and

(g) certain other rules may apply, depending on the concrete circumstances of the project (e.g. rules on the authorisation of the construction works, rules on the industrial security of the dangerous industrial objects, etc.).

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The procedure of transfer (from the state to the user (investor)) of the right of possession and use over a sector of subsoil (including when it comes to the right of exploration and extraction of natural resources) implies the following general steps:

(a) the GoM prepares the list of goods to be conceded;

(b) the GoM publishes, with the Official Gazette of Moldova, the information with regard to the goods to be conceded and the tender conditions;

(c) the results of the tender are approved by means of a decision of the GoM; and

(d) the conclusion (between the user (investor) and MARDE is that of a concession agreement) of the concession agreement (i.e. the user (investor) obtains the right of possession and use over the sector of subsoil, whereas the owner (state) keeps the right of disposition). Pursuant to the PPP Law, the concession agreement is a form of public-private partnership.

A concession agreement cannot be concluded for more than 50 years. In case of concession of the right to extract natural resources, the retribution for such extraction is made in the form of periodical payments (a share from the volume of production/sales).

The Concessions Law expressly stipulates that the state guarantees the protection of the investments of the user (investor); it cannot interfere with the user's (the investor's) business activity, unless such activity violates the provisions of the applicable legislation.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

For the purpose of conclusion of the concession agreement, the potential user (investor) is to file with MARDE the information on its financial means, special technological equipment and staff, which are necessary for the respective type of works in the subsoil sector.

Further, the investor's activity in the subsoil sector requires a list of permits (issuable by the Moldovan authorities). A general (non-exhaustive) list of such permits is indicated below:

(a) the licence for the production of natural gas (issuing authority: NARE, validity term: 25 years, state fee: Moldovan Lei (*MDL*) 3,250 (*cca.* EUR 160));

(b) the act on the confirmation of the geologic limits (*Ro. perimetru geologic*) (issuing authority: the Agency for Geology and Natural Resources, validity term: five years, state fee: free of charge);

(c) the conclusion of the state ecology expertise (issuing authority: the Environment Agency (*EA*), validity term: the period of implementation of the project, state fee: free of charge);

(d) the environment permit (as result of the environmental impact assessment) (issuing authority: EA, validity term: four years, state fee: free of charge);

(e) the urbanism certificate for projection of works of public utility of national interest (issuing authority: the Ministry of Economy and Infrastructure (*MoEI*), validity term: 24 months, state fee: free of charge);

(f) the construction authorisation(s) for works of public utility of national interest (issuing authority: MoEI, validity term: for the period of the construction works, state fee: free of charge);

(g) the positive conclusion of the expertise in the domain of industrial security (issuing entity: an authorised expertise entity, validity term: five years, fee: depends on the complexity of the activity, equipment, etc.); and

(h) the sanitary authorisation for the functioning of the facility (issuing authority: the National Agency for Public Health, validity term: five years, state fee: free of charge).

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Moldovan legislation neither contains a prohibition on the incorporation by the Moldovan state (as the owner of the subsoil resources), through the Moldovan authorities, of entities exploring and/or extracting oil and natural gas, or on the participation of the state with the share capital of such entities, nor does it provide for a mandatory participation of the state with the share capital of the entities exploring and/or extracting oil and natural gas.

From the currently available information, the GoM issued, on 30 December 2016, a decision on the approval of the results of a tender on the selection of Frontera Resources International LLC to perform works on geological exploration of hydrocarbons on the territory of Moldova. Pursuant to Decisions of the GoM no. 895 dated 20 July 2016 and no. 1439 dated 30 December 2016, the works of exploration and potential exploitation (extraction) of hydrocarbons on the territory of Moldova are conceded to the investor on the basis of a concession agreement, the state being entitled to receive a share from the volume of production/sales. We are not aware of any participation of the state with Frontera Resources International LLC, or with another entity performing works of exploration and potential exploitation (extraction) of hydrocarbons on the territory of Moldova.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The exercise of certain activities in connection with oil and natural gas development (production) is done against payment of consideration. In particular, the following types of fees/taxes can be distinguished:

(a) statutory taxes for certain activities, provided by the Tax Code of Moldova:

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- 2% of the contractual value of the works – for geological prospecting activities;
- 5% of the contractual value of the works – for geological exploration activities; and
- 20% of the value of the extracted resources – for extraction of natural gas and oil;

(b) the retribution provided by the concession agreement, in the form of periodical payments (a share from the volume of production/sales) – for extraction of natural resources (including natural gas and oil). Generally, the amount of the retribution (calculation formula) is indicated in the investor's offer (bid) for participation with the tender, organised in respect of the conceded goods; and

(c) fees in connection with the issuance of certain types of permits (licence, authorisations and certificates).

3.6 Are there any restrictions on the export of production?

Moldovan legislation does not provide for specific restrictions on the export of oil (petroleum products) or natural gas, except for crises or emergency situations (in respect of the natural gas).

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Pursuant to Law no. 62 dated 21 March 2008 "On Foreign Exchange Regulation", the payments and transfers within the current monetary (currency) transactions (*Ro. operatiuni valutare curente*) between residents and non-residents are generally performed without restrictions. In this context, the law provides for a list of transactions qualified as current monetary (currency) transactions (*Ro. operatiuni valutare curente*), including the transactions performed within the international trade of goods with an initial repayment term of one year.

On the other hand, Law no. 1466 dated 29 January 1998 "On the Regulation of the Repatriation of Money, Goods and Services Derived from Foreign Economic Transactions" provides for the local (Moldovan) entity's obligation to register with its local bank account the financial means derived from the export of goods abroad within two years, calculated as of the date of shipment of the respective goods. There is a risk of application of a fine (of 0.1% of the amount of non-repatriated funds for each calendar day of delay (but not more than 40% of the amount of non-repatriated funds)) in case of the local entity's failure to repatriate the financial means derived from the export of goods abroad within the indicated statutory period.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Except for cases involving the reorganisation of the entity, the transfer, partially or entirely, to a third party of the conceded goods (rights or interests) is prohibited. None of the permits (licence, certificates and authorisations) issued for the purpose of the exploration and exploitation (extraction) of natural resources (including natural gas and oil) can be transmitted to a third party.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Both the tender conditions and the concession agreement may contain an obligation for the investor (private partner) to provide guarantee(s) in connection with its offer (bid) and/or for the execution of its rights under the respective agreement.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The PPP Law admits the possibility of the investor (private partner) pledging the object of the public-private partnership (including rights to explore and extract natural resources (including natural gas and oil)), under the condition of procuring the public partner's (state authority's) consent. Such provisions are, however, in conflict with the provisions of the Concessions Law (as indicated at question 3.8 above), pursuant to which the transfer to a third party of the conceded goods (rights or interests) is prohibited (the pledge of certain rights (having as potential effect the transfer of such rights to a third party) is also prohibited).

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

A general (non-exhaustive) list of permits (issuable by the Moldovan authorities for the investor's activity on the subsoil sector) is indicated at question 3.3 above.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

The CS provides for the obligation of the user (investor) to liquidate the mining works, facilities and structures which are not intended to be further used. Moreover, the beneficiary of the subsoil sector (investor) is to create a fund for the liquidation of such mining works, facilities and structures, as well as for the rehabilitation of the degraded plots of land. The size of such fund depends on the concrete project.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The Natural Gas Law is the primary legislation regulating the activity of natural gas storage. Such activity is performed on the basis of a licence, issued by NARE for a period of 25 years. The number of such licences is not limited. From the currently available information, there are no licences issued by NARE for the activity of storage of natural gas.

The natural gas storage operator (*SO*), which is a part of a vertically integrated undertaking (*VIU*), is to be independent from other activities which are not connected with the activity of natural gas storage. In order to ensure the independence of the SO, the following minimum requirements are to be met:

(a) management separation, meaning that those persons responsible for the management of the SO may not participate in company structures of the VIU responsible, directly or indirectly, for the day-to-day operation of the production and supply of natural gas;

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(b) appropriate measures must be taken to ensure that the professional interests of persons responsible for the management of the SO are taken into account in a manner that ensures that they are capable of acting independently; and

(c) the SO must have effective decision-making rights, independent from other parts of the VIU, with respect to assets necessary to operate, maintain or develop the natural gas storage.

Access to the storage and pipeline storage is to be granted to all the existing and potential users in a transparent, objective and non-discriminatory manner. In order to ensure the supply of natural gas to consumers and to organise access to ancillary services, access to the gas storage facilities is granted on the basis of the tariffs established in accordance with the methodology approved by NARE.

The SO has the obligation to publish on its electronic page the information required for ensuring efficient access to the gas storage operated by such SO.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Pursuant to the Natural Gas Law, transactions involving sale-purchase of natural gas, including import or export transactions, transactions involving sale-purchase of interconnection capacities, and of other ancillary products, where the producers, TSOs, DSOs, SOs and suppliers participate, are performed on the natural gas wholesale market.

On the natural gas wholesale market, sale-purchase transactions are performed on the basis of bilateral agreements, taking into account the offer and demand, as a result of competitive mechanisms or negotiations. All the natural gas market participants are entitled to engage in bilateral transactions, including bilateral transactions of export or import of natural gas.

Sale-purchase transactions of natural gas on the natural gas wholesale market are to be conducted in a transparent, public and non-discriminatory manner.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Pursuant to Law of the Republic of Moldova no. 451 dated 30 July 2001 "On the Petroleum Products Market" (*Ro. Legea privind piata produselor petroliere*) (*Petroleum Products Market Law*), the import of petroleum products is performed on the basis of a licence, issued by NARE for a period of five years. In order to ensure the energy security of the country, certain special requirements are imposed to the importers of petroleum products:

(a) holding of Gasoline/Diesel storage with a capacity of at least 5,000 cubic metres and a capital of at least MDL 8 million (*cca.* EUR 400,000) – for the importers of Gasoline and/or Diesel; and

(b) holding of LPG storage with a capacity of at least 150 cubic metres – for the importers of LPG.

Farmers are excepted (in certain conditions) from the requirement to hold a licence for the import of petroleum products (Diesel). They are, however, required to request an authorisation from NARE.

The export (re-export) of petroleum products can be performed only by the importers of petroleum products (i.e. by entities holding licences for the import of petroleum products) and on the basis of an authorisation granted by NARE.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Law of the Republic of Moldova no. 592 dated 26 September 1995 "On the Magistral Pipeline Transportation" (*Ro. Legea privind transportul prin conducte magistrale*) (*Law 592/1995*) stipulates that the transportation pipelines may be owned either by private entities or by the state. However, the plots of land on which such pipelines are located are owned by the state and transferred into the use of the private entities (TSOs). There are no specific limitations when it comes to financing the construction of transportation pipelines, including of state importance. The sources of financing can be either the state budget, the funds of the pipelines transport operators, bank credits and loans.

Generally, agricultural plots of land with low quality (*Ro. bonitate scazuta*) or plots of land which are not suitable for agricultural purposes are used for the construction of transportation pipelines. Agricultural plots of land of high quality are used for the construction of transportation pipelines in exceptional cases and only on the basis of a decision of the GoM. The expropriation of the plots of land (if needed) and the change of destination of such plots of land which are to be used for the construction of transportation pipelines are also performed on the basis of decisions of the GoM.

Apart from those indicated above, the Natural Gas Law contains certain conditions for the exercising (including of the TSOs) of the right of use by the system operators over the privately owned plots of land for execution of works which are necessary, *inter alia*, for the construction, rehabilitation and modernisation of the network (e.g. consent, prior notification and obligations).

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

Law 592/1995 requires that the construction of the transportation pipelines is to be ensured by specialised construction organisations. Such organisations are responsible for the compliance of the construction works with the applicable legislation, are liable for the damages caused during the construction works (including compensation of the rehabilitation of the land), and obliged to correct the defects detected at the constructed pipeline during the first three years of exploitation.

Given the impact of a potential project involving the construction of transportation pipelines, and depending on the concrete circumstances of such project, certain permits (certificates and authorisations) are required (including the conclusion of the state ecology expertise, the environment permit (as a result of the environmental impact assessment), the urbanism certificate for projection of works of public utility of national interest, the construction authorisation(s), the positive conclusion of the expertise in the domain of industrial security, and the sanitary authorisation).

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6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

As indicated at question 6.1 above, the plots of land on which such pipelines are located are owned by the state and transferred into the use of the private entities (TSOs) – the Natural Gas Law indicates that such transfer into use (for the purposes of the construction, maintenance, exploitation, rehabilitation and modernisation of the natural gas transportation and distribution networks) is performed on a free-of-charge basis.

The privately owned plots of land needed for the construction of transportation pipelines can be expropriated by the GoM, if the respective construction works are to be considered of public utility (*Ro. cauza de utilitate publica*), and under the condition of payment to the expropriated owner of compensation.

Also, as indicated at question 6.1 above, the Natural Gas Law provides for a right of access by the system operators (including of the TSOs) through privately owned plots of land for the purpose of execution of works which are necessary, *inter alia*, for the construction, rehabilitation and modernisation of the network (consent, prior notification and obligations).

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

The TSO is obliged to grant to existing/potential users access to the natural gas transportation network in a transparent, objective and non-discriminatory manner, on the basis of an agreement, and at tariffs established in accordance with the methodology approved by NARE. The TSO has the obligation to publish on its electronic page the information necessary for ensuring efficient access to the gas transportation network operated by such TSO.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Pursuant to the Natural Gas Law, in order to execute its duties, including with regard to the trans-border transportation of natural gas, the TSO is to cooperate with the TSOs from neighbouring countries, in conformity with the agreements concluded with such operators.

Also, the individuals/legal entities are generally entitled to request the connection of their use/production/storage facility to the transportation network of the TSO performing the activity within the territory indicated in its licence.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

As indicated at questions 6.4 and 6.5 above, the TSO is obliged to grant to existing/potential users access to the natural gas transportation network in a transparent, objective and non-discriminatory manner. In order to manage access of third parties to the gas transportation system, the TSO is under obligation to keep an electronic register indicating the information with regard to each access point, including the identity of the third party, the existing supplier, the address of the consumption point, the contracted flow, the connection point, the delimitation point, the pressure in the delimitation point, and the characteristics of the measurement equipment.

Access to the natural gas transportation network can be generally refused (a) in case of absence of system capacity, (b) in case the granting of access would prevent the TSO from executing its public service obligations, or (c) in case serious economic and financial difficulties incurred due to the "take or pay" obligations.

The TSO refusing access to the system due to absence of capacity is obliged to take the necessary measures to ensure access of the third party to the system, under the condition that (a) such measures are economically justifiable, or (b) when the third party requesting access is ready to bear the costs in connection with such necessary measures.

The TSO is obliged to inform NARE on each and any case of congestion and of refusal of access to the natural gas transportation system, as well as on the measures which are intended to be taken to resolve such situations.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Generally, under the Natural Gas Law, access of third parties to the natural gas transportation system is performed on the basis of an agreement and at tariffs established in accordance with the methodology approved by NARE.

However, we understand that the terms which are not expressly regulated by NARE may be negotiated between parties.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Both the activity of transporting natural gas and the activity of distributing natural gas can be performed on the basis of licences only, such as those issued by NARE, for a period of 25 years and against a state fee of MDL 3,250 (*cca.* EUR 160). The TSO is to also obtain a certificate confirming compliance with the independence and unbundling rules.

There are currently two licences for the transportation of natural gas and 25 licences for the distribution of natural gas issued by NARE.

The general principles on access to the natural gas transportation network (which are similar to those of access to the natural gas distribution network) are outlined at question 6.6 above.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

As indicated at question 7.1 above, the licence for the activity of distributing natural gas is the main permissive act entitling an entity to perform such activity. Depending on the concrete circumstances of the activity, certain other permits may be required (the conclusion

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of the state ecology expertise, environment permit, urbanism certificates, construction authorisations, positive conclusions of the expertise in the domain of industrial security, sanitary authorisations for the functioning of the facility, etc.).

7.3 How is access to the natural gas distribution network organised?

A DSO is obliged to grant to existing/potential users access to the natural gas distribution network in a transparent, objective and non-discriminatory manner, on the basis of an agreement and at tariffs established in accordance with the methodology approved by NARE. The DSO has the obligation to publish on its electronic page the information necessary for ensuring efficient access to the gas distribution network operated by such DSO. In order to manage access of third parties to the gas distribution system, the DSO is under obligation to keep an electronic register indicating the information with regard to each access point, including the identity of the third party, the existing supplier, the address of the consumption point, the contracted flow, the connection point, the delimitation point, the pressure in the delimitation point, and the characteristics of the measurement equipment.

Access to the natural gas distribution network can be generally refused (a) in case of an absence of system capacity, (b) in case the granting of access would prevent the DSO from executing its public service obligations, or (c) in case of serious economic and financial difficulties incurred due to the "take or pay" obligations. The DSO refusing access to the system due to the absence of capacity is obliged to take the necessary measures to ensure access of the third party to the system, under the condition (a) such measures are economically justifiable, or (b) when the third party requesting access is ready to bear the costs in connection with such necessary measures.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

As indicated at question 7.3 above, the DSO refusing access to the system due to absence of capacity is obliged to take the necessary measures to ensure access of the third party to the system, under the condition (a) such measures are economically justifiable, or (b) when the third party requesting access is ready to bear the costs in connection with such necessary measures. In connection with the refusal of the DSO (i.e. in granting access to its natural gas distribution network), the third parties may address a claim to NARE, which will check the DSO's execution of its obligations under the law. DSOs must provide information on the measures required for the development of the natural gas distribution network, as well as on the concrete terms for execution of such development.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The fees for the DSOs' services are approved by NARE and published with the Official Gazette of Moldova.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Except for the limitations under the unbundling rules, there are no restrictions or limitations in relation to acquiring an interest in a natural gas utility, or in the transfer of assets forming part of the distribution network.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

The Natural Gas Law is based on the assumption of an open natural gas market.

Transactions involving the sale-purchase of natural gas and of other ancillary products are executed on the natural gas market, which is constituted of the wholesale market of natural gas and the retail market of natural gas.

Transactions involving the sale-purchase of natural gas, including import and export transactions and sale-purchase transactions of interconnection capacities, between the producers, TSOs, DSOs, SOs and suppliers are executed on the wholesale market of natural gas. On the wholesale market of natural gas, sale-purchase transactions are performed on the basis of bilateral agreements, taking into account the offer and demand as a result of competitive mechanisms or negotiations.

Transactions involving the sale-purchase of natural gas with end-consumers are executed on the retail market of natural gas, on the basis of the agreements on the supply of natural gas (*Ro. contracte de furnizare a gazelor naturale*) concluded between the suppliers and the end-consumers. The supply of natural gas to household consumers and small enterprises is generally performed at regulated prices.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

We are not aware of any restrictions on the types of commodities that can be traded.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Currently, there are no LNG facilities in Moldova.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

LNG is not particularly regulated under the Natural Gas Law.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

No, there is no such particular regulation.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

As there are no LNG facilities in Moldova, access to LNG facilities is not particularly regulated.

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10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The main normative act in the domain of petroleum products is the Petroleum Products Market Law. The import, wholesale and retail of Diesel, Gasoline and LPG is performed on the basis of a licence issued by NARE for a period of five years.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The wholesale of petroleum products is performed at non-regulated prices, on the basis of negotiated agreements. As regards the retail of petroleum products, NARE has the attribution to impose a maximum retail price.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

NARE has the general duty to create the necessary conditions for effective competition in the natural gas market, including by promoting, in its normative acts, the principles of equity, transparency and non-discrimination. NARE monitors the natural gas market and performs controls on the timely detection of abuses on the natural gas market.

Such attributions of NARE, however, do not affect the competence of the Competition Council of the Republic of Moldova (*CC*) to ensure the application of the legislation on the protection of competition in the territory of Moldova.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Competition Law no. 183 dated 11 July 2012 (*Ro. Legea Concurentei*) (*Competition Act*) is the main normative act setting the legal framework for the protection of competition, including with regard to the prevention and counteraction of anti-competitive practices, unfair competition, as well as with regard to the implementation of economic concentrations.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

Under the Competition Act, CC has the right (a) to investigate anti-competitive practices, unfair competition, other violations in the domain of competition, state aid and advertising, and (b) to ascertain violations of the legislation on the protection of competition, state aid and advertising, and to impose interim measures with regard to such violations, as well as to apply sanctions.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

CC is competent to: examine the notifications on economic concentrations (*Ro. concentrare economica*) filed by the concerned entities (phase I); initiate investigations, in case notified that an economic concentration is qualified as presenting doubts with regard to its compatibility with the competition environment (phase II); and issue decisions on the compatibility of the economic concentration with the competition environment.

The following types of economic concentrations are covered by the Competition Act:

(a) mergers between (two or more) previously independent undertakings, or certain parts of undertakings previously independent; and

(b) acquisitions – by one or several persons already controlling one or several undertakings, or by one or several undertakings, either by acquisition of shares or assets, or on the basis of an agreement or by other means, of direct or indirect control over one or several undertakings or parts of thereof, including the creation of a joint venture, which will fulfil durably all the functions of an autonomous economic entity.

An economic concentration has to be notified to the CC if the following thresholds are reached (on the basis of the turnover in the previous financial year):

(i) the combined turnover of the undertakings concerned exceeded MDL 25 million (*cca.* EUR 1.21 million); and

(ii) at least two of the undertakings concerned had a total turnover exceeding MDL 10 million (approx. EUR 0.48 million) in Moldova.

The local competition legislation applies equally to economic concentrations carried out by local and/or foreign entities.

The notifying party may start pre-notification contacts with CC (the relevant information concerning the proposed merger shall be submitted at least three working days before the date of the meeting).

Once CC considers that it has all of the data and documents enabling it to decide on the case, it will declare the notification *effective*. This is the date from which the term of 30 business days for issuing a decision starts running. Within such term of 30 business days, CC is to issue a decision:

- declaring the merger compatible with the competition environment; or
- launching an investigation, if CC concludes that the merger raises serious doubts on the merger's compatibility with the competition environment.

If the merger enters into phase II, the overall duration of the assessment may take up to 120 business days.

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12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There is a general rule in Law no. 81 dated 18 March 2004 "On Investments in Entrepreneurial Activity" (*Ro. Legea cu privire la investitiile in activitatea de intreprinzator*), pursuant to which investments in Moldova cannot be subject to discrimination on the basis of citizenship, domicile, residence, place of registration or activity, state of origin of the investor or of the investment, etc.

We are not aware of any special requirements or limitations on acquisitions of interests in the natural gas sector by foreign companies (if compared with the requirements for local companies).

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The regulatory policy in respect of the oil and natural gas of Moldova is especially influenced by the provisions of the Treaty Establishing the Energy Community dated 25 October 2005 (*the EC Treaty*). Moldova is a member of the Energy Community as of 1 May 2010. By adopting the Energy Community Treaty, Moldova made legally binding commitments to adopt core European Union energy legislation, the so-called "*acquis communautaire*".

With the adoption of the Natural Gas Law, Moldova transposed the Third Energy Package. Numerous secondary legislative acts are yet to be adopted as a pre-condition for Moldova to implement the natural gas *acquis* in real terms.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Pursuant to the Natural Gas Law, misunderstandings between gas companies in connection with such Natural Gas Law may be examined by NARE. The regulator is to issue a decision within two months (extendable by another two months), as of the date of filing by a gas company of the respective claim. Further, NARE examines the disputes (including trans-border disputes) in connection with the refusal of a TSO to grant access to its natural gas transportation network. Also, NARE examines, within 30 business days (extendable by another 30 business days) the misunderstandings between the end-consumers, system users and gas companies, in connection with the provisions of the Natural Gas Law.

Apart from this, the Natural Gas Law stipulates that litigations between participants to the natural gas market are resolved in court. A court judgment can be appealed within 30 calendar days, as of the date of issuance of the judgment. Further, the decision of the Court of Appeal can be contested with the Supreme Court of Justice within two months, as of the date of communication of the integral decision of the Court of Appeal.

The Petroleum Products Market Law does not contain special (additional) procedures of resolution of the disputes between participants to the petroleum products market. Hence, litigations between participants to the petroleum products market are to be resolved either in court or by an arbitral tribunal, as indicated in the above paragraph.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Yes, Moldova has ratified:

(a) the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards – on 10 July 1998; and

(b) the Convention on the Settlement of Investment Disputes between States and Nationals of Other States – on 5 May 2011.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

Generally, there is no particular difficulty in litigating, or seeking to enforce judgments or awards, against government authorities or state organs (including any immunity). However, in order to be cost and time efficient, companies often try to resolve disputes without seeking a judicial remedy.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are not aware of any such dispute resolution cases.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

The Natural Gas Law

Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (the Third Gas Directive) has been fully transposed into the Natural Gas Law of Moldova. However, TSOs are currently exempted from complying with the TSO unbundling rules of the Third Gas Directive (until 1 January 2020). From a mere legal point of view, the TSOs, therefore, need to comply with Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003

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concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC (the Second Gas Directive) only.

Ungheni–Chisinau Pipeline Extension

The gas market of Moldova is illiquid (The State of Gas Market Integration in the Energy Community, Bucharest, 28 September 2017). In 2016, out of 1,038.4 million cubic metres of contracted gas imports 99.8% were acquired from Gazprom. Liquidity may be improved by diversification of gas supplies in Moldova. In 2016, Moldova signed loan agreements with the European Bank for Reconstruction and Development and the European Investment Bank for financing the Ungheni–Chisinau pipeline extension.

Draft Law on Creating and Maintaining a Minimum Level of Oil Products Stocks

The Moldovan authorities have drafted a law on creating and maintaining a minimum level of oil products stocks. The draft is in compliance with Directive 2009/119/EC of 14 September 2009, imposing an obligation to maintain minimum stocks of crude oil and/or petroleum products. However, the timeline for the law's adoption is not clear. The draft law foresees its entry into force on 1 January 2021.

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Our lawyers are regularly involved in both international and domestic energy matters including transactions, development projects, mergers and acquisitions, privatisations, public-private partnerships, regulatory matters, public procurement, strategic advice, competition matters and dispute resolution.

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Mozambique

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

According to the Mozambican National Petroleum Institute, Mozambique has proved natural gas reserves of over 100 trillion cubic feet, which means it will continue to be, as indicated in the past few years, the third-largest proved natural gas reserve holder in Africa, after Nigeria and Algeria.

Throughout the past five years, besides the already well-established onshore fields located in Pande and Temane in the south of Mozambique (operated by Sasol, a South African energy firm which exports natural gas via a pipeline that connects the Pande and Temane fields to South Africa – after processing the gas in a central processing facility), recently all attention has been on the Rovuma Basin area, close to the border of Tanzania – more specifically Areas 1 and 4, which are both offshore. The main players in Areas 1 and 4 of the Rovuma Basin include, among others, Anadarko, ENI, Total, Mitsui, Galp Energia, Kogas, Barhat Petroleum and most recently Exxon Mobil. The allure of such large reserves has caught the interest of these multinational oil and gas companies, which have been investing in prospection and, soon hereafter, construction of platforms and drilling for natural gas in the Rovuma Basin.

Currently, no LNG facilities exist in Mozambique; however, following the execution of several important agreements during the present year between the concessionaires of Areas 1 and 4 and the Mozambican Government, all is becoming aligned for the construction of what could be the first floating LNG facility in Africa, which shall have the capacity to produce up to 20 million tonnes per year starting from 2023 (current estimate).

Transportation and distribution of natural gas is at a very early stage, with the transport network consisting of the Mozambique-South Africa pipeline and the recent distribution network (a partnership between State-owned Empresa Nacional de Hidrocarbonetos and Korean Kogas) restricted only to certain districts of the capital city, Maputo. New transport pipelines shall be developed, connecting the gas-rich north and south of Mozambique. Similarly, natural gas storage facilities shall be built only after production of offshore natural gas commences.

There are currently no secondary markets for the sale and purchase of natural gas in Mozambique.

New players in the market with large-scale projects in the pipeline include Yara, which intends to produce fertilisers, Shell, which is interested in producing liquid fuels and Baobab Resources, with the aim of producing 1.3 million tonnes of iron and steel per year.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Total primary energy consumption in Mozambique is of 0.185 quadrillion BTUs.

Despite massive potential for electricity and fuel generation, lack of socio-economic development and access to electricity and natural gas networks in Mozambique means that energy consumption remains heavily dependent on firewood and other wood fuels (such as charcoal). Renewable energies represent 79.6% of total consumption, followed by petroleum at 17%, then natural gas at 3% and coal at 0.4%. (*Source: International Energy Statistics, 2012.*) Note that wood fuels are, perhaps inaccurately, included in the "Renewables" section.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Mozambique currently fully meets its natural gas needs and, as such, does not import natural gas.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Currently, most of Mozambique's natural gas is exported to South Africa (via the Temane-Pande pipeline), corresponding to roughly 82% of total production.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Compared to the country's burgeoning natural gas sector, the oil sector in Mozambique is relatively incipient.

Oil production was due to commence in 2015 in an oil field discovered next to the Temane natural gas field, also operated by

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Sasol. Production is expected to reach 15,000 barrels per day, and shall be used for exports to South Africa.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Please *cfr.* question 1.2 above. Oil represents 17% of the energy consumed in Mozambique, its volume steadily increasing in the last few years, reflecting the country's accelerating economic growth.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

We currently have no information indicating that Mozambique has already started producing crude oil (*cfr.* question 2.1 above).

2.4 To what extent is your jurisdiction's oil production exported?

We currently have no information indicating that Mozambique has already started producing crude oil (*cfr.* question 2.1 above).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The principal legislation relating to the exploration and development of the country's oil and natural gas reserves is as follows:

- Constitution of the Republic of Mozambique;
- Law no. 21/2014, August 18 (Petroleum Law);
- Decree no. 34/2015, December 31 (Petroleum Law Regulation);
- Ministerial Diploma no. 272/2009, December 30 (Licensing of Facilities and Petroleum Operations Regulation);
- Decree no. 56/2010, November 22 (Environmental Regulation of Petroleum Operations);
- Law no. 27/2014, September 23 (Petroleum Tax Law);
- Decree no. 32/2015, December 31 (Specific Regime of Taxation and Tax Benefits of the Petroleum Operations);
- Decree no. 63/2011, December 7 (Employment of Foreign Citizens in the Oil and Mining Sectors);
- Council of Ministers Resolution no. 27/2009, June 8 (Strategy for Concession of Areas for Petroleum Operations);
- Decree no. 31/2012, August 8 (Regulation on Resettlement Process Resulting from Economic Activities);
- Decree no. 56/2010, November 22 (Environmental Regulation for Petroleum Operations);
- Law no. 15/2011, August 10 (Public-Private Partnerships, Large Projects and Business Concessions, also known as the "Mega-Projects" Law);
- Decree no. 16/2012, June 4 (Regulation of the Mega-Projects Law); and
- Decree-law 2/2014, December 2 (Special Regime for the Rovuma Basin – Areas 1 and 4).

Additionally, for downstream, one should also bear in mind:

- Council of Ministers Resolution no. 63/2009, November 2 (Strategy for Development of a Natural Gas Market);
- Decree no. 45/2012, December 28 (Regulation on Import, Sale and Distribution of Petroleum Products); and
- Decree no. 9/2009, April 1 (Importation of Petroleum Products).

This legal framework is supplemented by concession contracts that specify rights and duties of the concessionaire and the Government.

The Constitution of Mozambique provides that all-natural resources, whether located on/in land, underground, inner waters, territorial sea, and the continental platform or in the Mozambican exclusive economic area are the property of the State. The Ministry of Natural Resources ("MIREME") is responsible for directing and executing the governmental natural resource policies and for the supervision of the National Petroleum Institute ("*Instituto Nacional de Petróleo*" – "INP"), created by the Council of Ministers under Decree no. 25/2004, 20 August, the INP being the regulatory authority responsible for the administration and promotion of the Petroleum Operations.

In Mozambican legislation, "Petroleum Operations" are defined as planning, preparing and performance of reconnaissance, appraisal, development, production, storage, transportation and the termination of such activities or the end of use of the infrastructure, including the implementation of decommissioning plans, sale or delivery of oil to the export point or agreed delivery point, such point being where oil is delivered for consumption or use or loaded as merchandise, including in the form of liquefied natural gas.

The High Authority of the Extractive Industry ("*Alta Autoridade da Indústria Extractiva*") was established in 2014 to supervise Petroleum Operations, but is not yet operational.

Also, the Mozambican Government has fulfilled its plan (established a few years ago) of creating an authority that is responsible for regulating, controlling and supervising the energy sector in Mozambique, i.e., the Energy Regulatory Authority ("*Autoridade Reguladora de Energia*" – "ARENE") through the approval of Law no. 11/2017, September 8 (the "Law").

Among the several powers attributed to ARENE, it is important to highlight its active role on three important fronts; namely:

(a) to instruct and process public tender procedures for the assignment of concessions for the production, transportation, distribution and sale of electric energy and distribution and sale of natural gas, to issue the respective opinion, as well as to request the transfer of concessions;

(b) to instruct and process the granting of licences for the processing, distribution and marketing of liquid fuels, and to issue opinions on applications for the transfer of licences; and

(c) to establish and approve the tariffs and prices for energy, gas and petroleum products regulated under the law and ensure its application. However, its members have not yet been appointed, and it is also awaiting the approval of its statute and the regulation of the Law (which should take place before the end of the year).

In addition to the aforementioned entities that play regulatory and supervisory roles, the State participates in Petroleum Operations through the national oil company "*Empresa Nacional de Hidrocarbonetos, E.P.*" ("ENH"), and any investor wishing to explore Mozambican oil resources must associate with ENH. ENH participates in all phases of Petroleum Operations, from research to production refinery, transportation, storage and commercialisation of oil and gas and their derivatives, including LNG and GTL, both in and out of the country.

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The Petroleum Law and Regulation aim to ensure increased competitiveness and transparency in the sector, as well as to reinforce the role of the State, the protection of national interests and the involvement of Mozambican nationals. In equal circumstances, preference is given to Mozambican persons or to foreigners that associate with Mozambican persons in the granting of concession rights. Additionally, it is established that oil and gas companies should be listed on the Mozambican Stock Exchange (which is still at an incipient stage).

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Petroleum Operations are performed under concession agreements which are generally attributed by public tender process; however, they may be attributed by simultaneous or direct negotiations in relation to areas that had already been declared available when (i) no concession was granted pursuant to a previous public tender, (ii) there is rescission, relinquishment and abandonment, or (iii) there is a need to join adjacent areas to a concession, when justified for technical and economic reasons. Concession contracts are of an administrative nature.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Private investment in upstream interests for conducting Petroleum Operations are granted through concession contracts and are generally attributed by a public tender process. Such rights may also be attributed by simultaneous or direct negotiations in relation to areas that had already been declared available when (i) no concession was granted pursuant to previous public tender, (ii) rescission, relinquishment and abandonment, or (iii) the need to join adjacent areas to a concession, where justified, due to technical and economic reasons.

Concession contracts are administrative contracts, subject to the authorisation of and supervision by the Administrative Court, the main clauses therein being subject to publication in the official gazette.

The following rights may be conferred under concession contracts:

- reconnaissance;
- exploration and production ("EPCC");
- pipeline construction and operation; and
- infrastructure construction and operation.

From the list referred above, the EPCC contract is the key contract applicable to upstream activities, as it grants an exclusive right to carry out petroleum exploration and production.

The MIREME has recently approved a new template EPCC, a draft of which is published in the INP website (http://www.inp.gov.mz/pt/Politicas-Regime-Legal/Modelo-de-Contratos-de-Pesquisa-e-Producao). The approval of such template follows the recent enactment of the main diplomas regulating this sector (the Petroleum Law and its Regulations). The annexes of the template EPCC include the template Joint Operating Agreement ("JOA").

The Reconnaissance Concession confers a non-exclusive right to perform preliminary appraisal and evaluation of the contract area and is granted for a maximum period of two years, non-renewable, and allows drilling up to a depth of 100 metres.

The EPCC confers on its holder an exclusive right to perform Petroleum Operations, as well as a non-exclusive right to construct and operate production and transportation infrastructure. The exclusive exploration right under the EPCC shall not exceed eight years and is subject to area abandonment provisions. In the event of a discovery, the concession-holder may maintain the exclusive right to complete the work initiated within a specific area, in relation to the appraisal period, to comply with his work and appraisal obligations and to determine commercial value and allow oil development and production. The concession-holder may maintain the exclusive right, under the development plan approved by the Government, to develop and produce oil and gas in the development area, subject to renewal for equal or shorter periods, as deemed most advantageous for national interest.

The Pipeline Construction and Operation Concession allows the concession-holder to construct and explore oil or gas pipelines for the transportation of crude oil and natural gas, should such operations not be covered under the EPCC agreement. Similarly, the infrastructure construction concession agreement allows the concession-holder to construct and operate oil production infrastructure, such as processing and conversion facilities that are not covered by an approved appraisal and production plan.

In the case of the Pipeline Construction and Operation, such agreements must also be thorough and include the specification of the oil or gas pipeline and provisions regarding the rights of use of land.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

According to the Petroleum Law, the State reserves the right to participate in Petroleum Operations involving any person and may participate at any stage, according to the contractually agreed terms and conditions. Such State participation is made through ENH and any investor interested in exploring Mozambican oil resources must associate with ENH. No indication is given as to what such stake should be, but we note that in the recent 5th Licensing Round, the ENH stake was indicated as 10%.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

In addition to the bonus payments, training programmes, relinquishment fund and other financial obligations set out in the concession contracts, entities entitled to perform Petroleum Operations are subject to all of the following general taxes: income tax; value-added tax; municipal tax (when applicable); and also to the specific petroleum tax regime. The petroleum tax regime levies a Production Tax ("*Imposto sobre a produção do petróleo*") on oil and gas produced in each concession area.

The cost recovery and production sharing mechanisms are also regulated, drawing on the traditional concepts of cost oil, available oil, profit oil and produced oil. Costs incurred by the concessionaire on oil operations, excluding interest and other financial costs, are recovered from 60% of the annual available oil – the portion exceeding this limit is transferred to the following years. In turn, profit oil is shared between the State and the concessionaire according to a variable scale, the result of which is obtained through a mathematical formula.

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The special rules foreseen to determine the Personal Income Tax ("*Imposto sobre o Rendimento das Pessoas Singulares*" – "IRPS") or Corporate Income Tax ("*Imposto sobre o Rendimento das Pessoas Colectivas*" – "IRPC") due on the income obtained from oil operations include, namely: (i) the characterisation of deductible and non-deductible costs and expenses; (ii) amortisation rules; (iii) thin capitalisation rules; (iv) registration of inventory; and (v) a withholding flat tax rate of 10% on the payment of services related to concession agreements undertaken by non-resident entities.

Transfer pricing rules are also further developed, including the application of the arm's length principle to the transfer of assets between different concession agreements held by the same concessionaire.

The tax regime also tightens the ring-fencing rules and clarifies that the IRPC of entities running Petroleum Operations under a concession agreement should, as a general rule, be calculated individually for every concession area (costs and income should also be determined separately in relation to each area) and each concession agreement area must have its own Tax Identification Number ("*Número Único de Identificação Tributária*" – "NUIT").

3.6 Are there any restrictions on the export of production?

In addition to the production sharing rules set out under the petroleum tax regime, the Petroleum Law also sets out that the Government should ensure that no less than 25% of the oil and gas produced in the national territory is destined for the national market and to regulate the acquisition, price and other matters inherent to the use of the aforementioned oil and gas quota. We further note that the oil companies are obliged to give the State preference in the acquisition of oil produced in the concession area, according to special legislation, when required for reasons of national interest.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Mozambique does not have a specific foreign exchange regime for oil and gas operations, besides the special regime approved for Areas 1 and 4 in the Rovuma Basin, which only apply to these projects. In general, such operations are subject to the general foreign exchange regime and to the terms and conditions set out in the individual concession agreements. As a result, the movement of funds in and out of Mozambique is subject to exchange controls and to the registration and approvals of the Central Bank of Mozambique.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The direct transfer of rights and duties attributed under a concession contract to a subsidiary or to a third party is subject to governmental approval and must observe Mozambican law. Such governmental approval is also necessary for the direct or indirect transfer of the participation interest in the concession agreement, including through the assignment of shares or any other form of ownership stake of the entity holding the concession rights.

In order to ensure compliance with the terms and conditions of the petroleum exploration authorisations, operators must present financial guarantees in terms to be regulated.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

The Petroleum Law also provides that operators should provide a financial guarantee to ensure performance of the terms and conditions set out in the authorisation.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The concession contract and the rights and duties arising thereunder cannot be freely transferred and are subject to governmental approval as set out under question 3.8 above.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

An environmental impact assessment ("EIA") approved by the Ministry of Coordination of Environmental Affairs ("MICOA") must be presented with the respective development plan. Additionally, the concession right-holder must present the necessary licences for use and enjoyment of land (secured according to the land legislation) and the authorisations for performance of Petroleum Operations on land or at sea.

International standards as well as specifically legislated technical requirements and health and safety rules for employees must also be complied with.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

The Environmental Impact Study Report comprehends the decommissioning and rehabilitation plan. A detailed Decommissioning Plan shall be prepared in consultation with the INP and submitted no less than two years prior to the date on which production operations are expected to cease, for the approval of the Minister with authority over the petroleum industry.

The Decommissioning Plan shall include, among others, the following items:

(a) tail-end production schedules and the economic threshold for termination of operations;

(b) alternatives for continuing Petroleum Operations;

(c) further use or subsequent disposal of facilities;

(d) plans for plugging and abandonment of production wells;

(e) a schedule of decommissioning activities and description of equipment needed for the restoration of land sites and/or the seabed;

(f) an inventory of dangerous material and chemicals existent in the facilities and plans for their removal; and

(g) evaluation of environmental impact of termination and abandonment activities.

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Activities falling in the A Category must proceed with the following stages: (i) pre-assessment of the proposed project by the relevant environmental department and provision of written response (including the indication of the number of the required copies of Terms of Reference ("ToR") and Studies on the Pre-Feasibility and Scoping Activities ("EPDA") to be submitted); (ii) appointment of a Government-registered environmental consultant; (iii) working with the environment consultant to develop an EPDA; and (iv) working with the environment consultant to develop the ToR. Subsequently, it will be required to submit the number of copies of the EPDA and ToR defined in the written response to the pre-assessment to the relevant environmental department.

Having received these documents, the relevant environmental Government department has 30 working days to respond to the applicant, either approving the EPDA and ToR or requesting alterations and re-submission. If the application is successful, the contracted Government-registered environment consultant undertakes the EIA based on the approved ToR.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/ requirements of the legislation?

Presently, the main production of natural gas comes from the onshore Pande and Temane fields, which are connected by pipeline to South Africa. Natural gas storage facilities shall be built after production of offshore natural gas commences and no specific legislation exists beyond the current legal framework.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

No specific regulatory limitations or rules apply. The national legislation and internationally accepted rules and principles governing the transport, storage and use of hazardous material must be complied with.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

The export (i.e. cross-border sale) or delivery of petroleum and petroleum products is subject to licensing.

Only entities licensed to distribute petroleum products may provide bunker services for the re-exportation of those products, provided that such activities are carried together with sales in the national market. Entities not based in the country, which seek to carry out bunker activities from Mozambique for the international shipping of products which are located in the country or purchased in a foreign currency exclusively for that purpose, and activities for transporting those products to and from neighbouring countries, must do so through the licensed entities. In what concerns the import of refined oil and liquefied petroleum gas, IMOPETRO (at least 51% held by the State company PETROMOC, S.A., and by the authorised distributors in proportion to their market stake) has exclusivity on the import and sale of such products to retailers in Mozambique.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

As referred to above, an EPCC may attribute the non-exclusive right to construct and operate production and transportation infrastructure to transport the crude oil and natural gas produced in the concession area, unless such pipelines already exist and are available in commercially acceptable terms. When such rights are not granted under an EPCC, they may be attributed under a Pipeline Concession Contract.

The holders of pipeline rights – whether under the EPCC or the Pipeline Concession Contract – are obliged to transport third-party oil on a non-discriminatory and commercially acceptable basis provided (i) there is available pipeline capacity, and (ii) there are no unsurpassable technical issues that would exclude the pipeline from satisfying such third-party requests. The holders of pipeline rights may be obliged to increase the pipeline capacity to allow the above as long as (i) such increase does not cause an adverse effect on the pipeline's technical integrity or safety, and (ii) third parties have sufficient funds to bear the cost of increase in pipeline capacity.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

Upstream pipeline construction rights may be attributed under an EPCC or under a Pipeline Concession Contract and in either case an EIA approved by the MICOA must be presented with the respective development plan. Additionally, the concession right-holder must present the necessary licences for use and enjoyment of land (secured according to the land legislation) and the authorisations for performance of Petroleum Operations on land or at sea.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

According to the Mozambique legal regime, land is owned by the State and cannot be sold, disposed of or pledged. However, a lesser right can be granted that allows the use and enjoyment of land ("*Direito de Uso e Aproveitamento de Terra*" – "DUAT"). The grant of a concession entitles the holder to apply for a licence of use and enjoyment of land under the general land legislation (Law no. 19/97, October 1) and to require that rights of way be granted. Fair indemnification will need to be paid to any holders of DUAT and the resettlement of the population must be ensured.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Please see question 6.6 below.

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6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

There are presently no oil pipelines. The current natural gas transportation and distribution network consists of the Mozambique-South Africa pipeline and a recent distribution network limited to certain districts of the capital city, Maputo. Reports indicate that a new pipeline is under construction further north, connecting to the Mozambique-South Africa pipeline.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Any holder of a licence for distribution, landing terminals, storage or oil pipelines, is obliged to receive, issue, handle, store, mix, or manage, without discrimination and in non-discriminatory commercial terms, third-party petroleum products at their petroleum storage facilities, landing terminals or oil pipelines, provided that:

(a) there is available space at the petroleum facility in question; and

(b) there are no insurmountable technical problems which impede the use of the petroleum facility to meet requirements of third parties.

If the available capacity of the petroleum facility in question, or the dimensions or route of pipelines, is insufficient to meet the requirements of third parties, the licence-holder shall be obliged to make a modification to the facility so that, in commercially acceptable terms, third-party requests can be met, provided that:

(a) such modification does not have an adverse effect on the technical integrity or the safe operation of the petroleum facility; and

(b) third parties have sufficient funds to support the costs of the required modification.

The Minister responsible for the energy sector may waive compliance with the obligation provided above, on behalf of the holder of the licence for distribution, a landing terminal, storage or oil pipelines, as applicable, if reasonable efforts have been made to meet the requirements of third parties and to prove that it is not possible to receive, send, handle, store, mix or manage the third-party petroleum products or carry out the requested modification of the petroleum facility.

The holders of licences or operators of the petroleum facilities must act with transparency in the negotiation of access to their facilities, and they may not impose discriminatory conditions.

The holders of licences for distribution, loading terminals, storage or oil pipelines must make available, in non-discriminatory terms, the relevant records on the petroleum facility in question, to third parties who request it, in order to facilitate the negotiation of acceptable commercial terms.

If, within a period of six months after the notification of the request for access to the petroleum facility or to increase its respective capacity, the parties have not reached an agreement on the commercial or operational terms which ensure the access sought, the matter, depending on the terms of the contract, may be submitted for resolution:

(a) to an independent commission;

(b) to arbitration proceedings; or

(c) to the competent judicial authorities.

It is up to the Minister responsible for the energy sector to establish the methodology for third-party access to petroleum facilities.

In addition to its needs for supply to the national market, the entity in possession of a storage infrastructure in the ocean terminals must reserve at least 15% of the capacity of its facilities for third-party access to products for the national market.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Tariffs for third-party access to pipelines are not regulated and should be established in commercially reasonable terms and on a non-discriminatory basis, according to the standards that apply in the petroleum industry, and negotiations be conducted in good faith.

If six months after submitting the respective request, the parties have not reached an agreement on the commercial or operational terms for access, the matter may be submitted to resolution by an independent committee, arbitration or the competent courts of law.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

As mentioned above, the transport and distribution of natural gas is at a very early stage with the transport network consisting of the Mozambique-South Africa pipeline and the recent distribution network restricted only to certain districts of the capital city, Maputo. However, new transport pipelines are expected to be developed, connecting the gas-rich north and south of Mozambique.

Decree no. 44/2005, November 29, establishes the Regulation for Distribution and Commercialisation of Natural Gas, pursuant to which these rights are attributed by means of concession agreements resulting from a public tender process. The attribution of rights through direct negotiations is only envisaged when the public tender process had no bidders or in areas that have not been designated as "Concession Areas" for a distribution network or independent local networks by the MIREME. The concessionaire must be a commercial company, necessarily held by the successful tenderer(s), with the registered office and administration in Mozambique.

The concessionaire may be given exclusive distribution and commercialisation rights in the whole or part of a concession area for a certain period; however, once such exclusivity has ended, consumers are entitled to acquire natural gas from third parties.

The concession period for natural gas distribution and commercialisation networks is granted for a maximum of 25 years, and the concession for exploration of independent local networks shall have a maximum duration of 10 years.

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7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

The concessionaire must obtain a licence for use of the land necessary for the construction, installation and exploration of the concession infrastructure and pay the related taxes and compensations.

Construction may only commence after the necessary environmental licence has been obtained from the Ministry of the Environment and all studies and the MIREME must approve detailed engineering projects relating to the distribution network. Furthermore, the construction of natural gas infrastructure must necessarily involve a licensed assembly and installation company.

7.3 How is access to the natural gas distribution network organised?

The MIREME establishes the rules of negotiated access to the distribution network and the concessionaires should negotiate access rights with transparency, being barred from imposing any discriminatory conditions. The concessionaire should publish its main commercial terms of use within the two years following the end of its exclusivity, should such exclusivity have been initially granted.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

One of the general duties of the concessionaire is to supply natural gas in the best manner to serve consumer needs and interests and to contribute to the country's economic and social development. For such purpose, the concessionaire must, in the terms set out in the concession contract, supply all consumers who are in a condition to pay for such supply and comply with any other conditions necessary for such purpose.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

As mentioned in question 7.3 above, the MIREME establishes the rules for negotiated access to the distribution network and the concessionaires should negotiate access rights with transparency, being barred from imposing any discriminatory conditions. We further note that the MIREME regulates a maximum price for natural gas supplied to final consumers (Ministerial Decree no. 210/2012, September 12).

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

The concessionaire owns the distribution network and the installations and equipment necessary for its operation until the end of the concession period and is barred from burdening or disposing in any manner, whether fully or partially, the fixed assets effected to the concession without obtaining the prior approval of the MIREME. The assignment of the concession contract is subject to the prior approval of the granting authority.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

The State reserves the right to control the trading of liquefied hydrocarbons and gas, including LNG.

The State, its institutions and other public law entities have a determining role in promoting the realisation of the existing natural resources potential so as to provide access to the benefits of petroleum production and contribute to the social and economic development of the country.

The existing Petroleum Regulation aims to bring the legal framework of the oil business to the current economic order in the country, the developments in the oil sector, ensure competitiveness and transparency, and safeguard national interests.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

The Petroleum Law provides that a trading licence is required for the trading of gas, and defines gas as "*oil that under normal atmospheric conditions is in the gaseous state*", as well as unconventional gas, including methane gas associated with coal and bituminous shale gas.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

The current available general legal framework is silent in respect of the specific regulation of LNG facilities. Only Mozambique's Special Regime for Natural Gas Liquefaction Projects in Areas 1 and 4 of the Rovuma Basin (Decree-law 2/2014, December 2) – which applies to concessionaires under existing EPCCs – regulates any special purpose vehicles ("SPVs") established by such concessionaires and any persons entering into contracts with concessionaires or SPVs (contractors, financiers and employees) as well as their subcontractors, and in connection with activities relating to the development and operation of Offshore Areas 1 or 4 and which are undertaken under existing EPCCs or any other contracts with the Government of Mozambique.

Accordingly, any SPVs established by concessionaires must be incorporated in Mozambique, although SPVs for the purposes of raising finance or undertaking sales and shipping activities may be incorporated in any "transparent" jurisdiction where the government of the jurisdiction can verify the ownership, management, control and fiscal situation of the investor (subject to Mozambican Government consent). While this "transparent" jurisdiction standard is equivalent to the standard imposed on new concessionaires under the Petroleum Law, unlike the requirements of the Petroleum Law, neither the existing concessionaires of Areas 1 and 4 nor their SPVs are required to be listed on the Mozambican Stock Exchange.

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9.2 What governmental authorisations are required to construct and operate LNG facilities?

In Areas 1 and 4 of the Rovuma Basin, the Government shall approve the Development Plan submitted by the concessionaires prior to any construction of LNG facilities. Also, when applicable, a master depletion plan may be approved for the management of the tanks.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Currently, no LNG facilities exist in Mozambique. The future LNG facilities planned by Anadarko and ENI are expected to commence production only in 2023.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

The Petroleum Law (covering LNG processing) provides that the Mozambican Government may authorise concessionaires that have discovered oil and non-associated gas deposits 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.

Petroleum production, including LNG production activities, may be undertaken and authorised by the Government under an EPCC without the need for further licensing or concession.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Decree no. 45/2012, December 28, defines the regime for production, importation, receipt, storage, handling, distribution, trade, transport, exportation and re-exportation of petroleum products and the respective sale prices in the national territory. This Decree provides for the following licences:

(a) Production Licence;
(b) Storage Licence;
(c) Distribution Licence;
(d) Retail Licence;
(e) Exploration of Oil Pipeline Licence; and
(f) Exploration of Unloading Terminal Licence.

The aforementioned licences are generally granted by the MIREME; however, licences for retail activities in a petrol station are granted by the Provincial Directorates ("*Direcções Provinciais*") responsible for energy (except for storage or supply of compressed natural gas or when located within national roads protection areas, which are within the authority of the MIREME) and licences for retail activities in resale stations are granted by the Municipality or District Government in the respective areas of jurisdiction.

An entity may hold more than one of the aforementioned licences, as long as that does not condition the development of competitive markets for the petroleum products in accordance with the activities the entity pursues. However, the holder of a distribution licence cannot hold a retail licence except (i) in the case of liquid gas and compressed natural gas, and (ii) for the operation of a sole point of fuel supply for the purposes of training in each of the country's provinces.

In exceptional cases, the Minister responsible for the energy sector may authorise the distributor to operate more than one point of supply per province.

The production licence comprises the categories of large-scale production and small-scale production. The retail licence covers the operation of retail activities at fuel supply points and the operation of retail activities at points of resale.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

There are no specific requirements relating to the trade in oil as a commodity in Mozambique.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The publication of Law no. 10/2013 (the "Competition Law") on April 11 established the legal framework for competition in Mozambique and created the Competition Regulatory Authority ("CRA") to enforce it. The Competition Law is not specific for the oil and natural gas sector and comes as a result of the efforts made in recent years by the Mozambican Government to streamline economic initiatives and liberalise some key sectors, such as communications, ports, railways and financial services.

A step further was taken recently with the publication of the Statute of the CRA on August 1, 2014.

The CRA was conferred broad supervisory and sanctioning powers with regard to restrictive competition practices (such as cartel agreements and abuses of dominant position), and charged with clearing or prohibiting concentrations between undertakings that are subject to mandatory notification in Mozambique. The CRA's decisions may be appealed in court, namely to the Judicial Court of the City of Maputo, in the case of procedures leading to the application of fines and other sanctions, and to the Administrative Court, with regard to merger control procedures and requests for exemptions relating to restrictive agreements. The Statute also establishes a duty of co-operation on the part of undertakings and other entities subject to the activities of the CRA, in order to ensure the adequate performance of the authority's duties.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The new Competition Law has a wide scope, as it applies to both private companies and State-owned companies, and covers all economic activities with effects in Mozambican territory (with a number of exceptions).

It prohibits agreements and practices which restrict competition, both between competitors ("horizontal" practices), and between companies and their suppliers or customers ("vertical" practices), as well as abusive practices by dominant undertakings (including, among others, the refusal to grant access to essential infrastructure, unjustified termination of a business relationship) and abuse of the economic dependence of suppliers or customers.

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However, prohibited practices may be justified and exceptionally allowed if they lead to economic efficiencies, as well as if they promote the competitiveness of small and medium enterprises and the consolidation of the national economy (as long as such practices do not eliminate competition and are indispensable for the objective to be achieved).

The new law introduces merger control and all concentrations which meet the market share or annual turnover criteria, to be determined by the Council of Ministers, will be subject to mandatory notification to the CRA, within seven working days after conclusion of the agreement or its project, and cannot be implemented before clearance.

Violation of the prohibitions contained in the new law subjects infringing firms to fines up to 5% of the turnover of each company in the previous year. In addition, the breach of the duties to notify concentrations within the statutory period and to co-operate with the CRA is punishable with fines up to 1% of annual turnover.

The law also provides for penalty payments, where appropriate, as well as potentially serious ancillary sanctions, not only because the offender may find itself excluded from participating in tenders for five years, but because it can even find itself confronted with the possible break-up of the offending undertaking. Finally, agreements and practices concluded in breach of the law are null and void.

Recently, a proposal for a regulation implementing the Competition Law was made public, which, among other topics, further defines the subjective and material scope of the prohibitions under the Competition Law and determines the legal criteria for mandatory notification of concentrations to the CRA, with regard to the market shares and turnover of the parties. Specifically, pursuant to the referred proposal, notification is mandatory on undertakings having a market share equal or superior to 20% and an annual turnover above 100 million meticais (approximately EUR 2.5 million and USD 3.3 million).

Even though the application of the rules on merger control is dependent on the approval of the new regulation, when the new CRA starts functioning, the provisions on prohibited practices restrictive of competition shall be fully applicable, and the violation of such rules subjects the undertakings concerned to fines of up to 5% of the turnover of the preceding year, as well as other negative procedural consequences.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The CRA has broad supervisory, regulatory, investigatory and sanctioning powers, pursuant to which it will be able to inquire relevant persons, request documents and conduct searches and seizures and the sealing of the premises. The CRA will co-ordinate closely with the other sectorial regulatory authorities.

The CRA may assign different priorities to certain practices or sectors (under the designated "principle of opportunity") and in the last quarter of each year should publish its enforcement priorities for the following year.

The practical application of the law will depend largely on the organisation and functioning of the CRA, and the priorities it will set for the enforcement of competition law. Please refer to question 11.2 above for measures and sanctions that may be applied to anti-competitive practices.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

The Competition Law should, in principal, apply to this sector. However, there is one exception to its scope which relates to cases of a specific need for protection of a sector of the economy, in the benefit of the national interest or consumers' interest.

As the Competition Law is not yet being enforced, it is not possible to comment on timings.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

In order for foreign legal entities to be holders of the right to carry out Petroleum Operations, they must be registered in Mozambique and demonstrate that they have the technical capability and adequate financial resources for the effective conduction of Petroleum Operations.

Additionally, foreign legal entities which directly or indirectly hold or control legal entities that own rights under a concession contract shall be established, registered and administered under a transparent jurisdiction. This is understood as jurisdictions whereby the Government, in an independent manner, may verify the ownership, management and control, and fiscal situation of a foreign legal person who wishes to participate or participates in Petroleum Operations. Foreign legal entities that associate with Mozambican legal entities shall have a pre-emption right in the granting of concession contracts.

In the context of the acquisition of goods or services by Petroleum Operations right-holders, single or collective foreign entities that provide services to the Petroleum Operations must associate with single or collective Mozambican entities.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

While defining its scope, the Law states that it establishes the rules for the granting of rights to carry out Petroleum Operations in the Republic of Mozambique and beyond its borders insofar as it is in accordance with international laws.

The definition of "good petroleum industry practice" refers to all those practices and procedures that are generally employed in the international petroleum industry and aimed at the prudent management of petroleum resources, including the conservation of pressure, ensuring the regularity of Petroleum Operations and observing safety aspects, environment preservation, technical and economic efficiency.

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The Government ensures the rigorous observation of the protection and rehabilitation of environmental norms, in the terms of the law and the conventions and good international practices.

Furthermore, the holders of petroleum operation concession rights shall perform them in accordance with the environmental legislation and other legislation applicable and adopt measures for the protection of the environment which are in accordance with internationally accepted standards. Petroleum Operations right-holders have an obligation to promote public safety and adopt the required measures to ensure the safety and hygiene of their workers in accordance with the national and international regulations applicable in the Republic of Mozambique.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Disputes in the oil and natural gas sector, even when one of the parties is a Government authority/regulator, can be subject either to arbitration or to the judicial authorities. Law no. 7/2014, February 28 ("*Lei sobre o processo administrativo contencioso*"), regulates the judicial procedures between the administration and any individual or company. This law includes a chapter on arbitration, stating that an arbitral tribunal may solve any dispute concerning (i) administrative contracts, and (ii) non-contractual civil liability of the administration arising from public management acts. Specifically concerning the oil and natural gas sector, one of the specific legal guarantees attributed to Petroleum Operations right-holders under the Petroleum Law is the possibility to resort to international arbitration for the resolution of disputes when all alternative resolutions means are extinguished. The Law establishes that when a dispute arising from a concession contract is not solved by negotiation, it can either be subject to the local courts or to arbitration, according to the terms and conditions agreed in the concession contract.

Arbitration between the State of Mozambique and foreign investors shall be conducted in accordance with:

(a) the law that governs arbitration, conciliation and mediation as alternative methods of conflict resolution;

(b) the rules of the International Centre for the Settlement of Disputes between States and Nationals of Other States ("ICSID"), adopted in Washington on March 15, 1965, or pursuant to the Convention on the Settlement of Disputes between States and Nationals of Other States;

(c) the rules set out in the ICSID's Additional Facility adopted on September 27, 1978 by the Administrative Council of the International Centre for Settlement of Investment Disputes between States and Nationals of Other States, whenever the foreign entity does not meet the nationality requirements provided for in Article 25 of the Convention; and

(d) the rules of such other international instances of recognised standing as agreed by the parties in the concession contracts referred to in this Law, provided that the parties have expressly defined in the contract the conditions for implementation including the method for the designation of the arbitrators and the time limit within which the decision must be made.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Mozambique is a signatory to and has ratified both the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID").

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

In Mozambique, the Government or any Government authority is subject to the law and the judicial authorities. As mentioned above, Law no. 7/2014, February 28, regulates the judicial processes between the administration and any individual or company and establishes that in cases where the enforcement of a judgment (i) is absolutely and definitely impossible, or (ii) causes serious damage to the public interest, there is a legitimate cause for the non-enforcement of that judgment. Additionally, the Civil Procedure Code establishes that the State's assets that are used for public utility cannot be attached in the enforcement of a judgment, unless when the enforcement pursues the rendering of that same asset or the payment of a debt secured by collateral.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

There have been no such instances that we are aware of.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

This is answered in the questions above, as the law we have commented upon is quite recent.

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Henriques, Rocha & Associados Sociedade de Advogados, Lda. (HRA Advogados) was founded by a group of lawyers of Mozambican nationality, and is a leading law firm in Mozambique due to its dynamism, innovative capacity and the quality of service it provides. Building a legal practice capable of meeting our clients' needs in the Mozambican market and contributing to the growth and development of the legal market in Mozambique are the main goals of the HRA Advogados team. Our firm was created in the context of an association with Morais Leitão, Galvão Teles, Soares da Silva & Associados (MLGTS), a top-ranking Portuguese law firm. We work in close connection with the firm's Africa Team; always with respect for, and in strict compliance with, the cultural norms applicable in Mozambique. We are also members of the MLGTS Legal Circle, an international network created by MLGTS for a select set of jurisdictions, including Angola, Mozambique and Macau (China). The firm works very closely with the other member firms of the MLGTS Legal Circle, which enables us to maximise inherent synergies.

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Norway

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Norway has abundant natural gas resources located in the seabed of its continental shelf (NCS). Norway is among the world's largest natural gas exporters and ships most of the natural gas produced through export pipelines to the European market.

Total natural gas exports from the NCS in 2016 were 115 billion Sm^3 (approx. 108.9 billion Sm^3 through pipeline and approx. 6.1 billion Sm^3 in the form of LNG). At year-end 2016, 2.217 billion Sm^3 of natural gas had been produced from the NCS in total. Remaining recoverable natural gas reserves are estimated to be 3.853 billion Sm^3. There is no onshore hydrocarbon production in Norway.

Norwegian natural gas maintained its market shares in the European market in 2016. Norwegian natural gas supply represents approx. 25% of EU's natural gas demand (including LNG). The ability to maintain and even increase production rates, and a readily available and efficient gas transportation system, combined with a predictable long-term government petroleum policy, have all contributed to the continued attractiveness of Norwegian natural gas.

Remaining undiscovered natural gas reserves are to a large extent expected to be located in virgin areas of the NCS with limited or no infrastructure in place, particularly in the northern parts of the NCS – more specifically, in the Norwegian Sea or in the Barents Sea. Major discoveries have to be made if natural gas export solutions are to be established.

Norway produces both associated and non-associated natural gas and has a very strict flaring/venting policy in order to maintain reservoir pressure and reduce emissions. Natural gas that is not sold or used for production purposes is re-injected.

All natural gas is sold by the NCS Production Licensees on an individual basis. However, joint sales of volumes by an Operator on behalf of Licensees are not uncommon. Statoil markets and sells the State's direct financial interest (SDFI) production managed by Petroro AS on behalf of the Norwegian State (see below). In aggregate, Statoil markets and sells about 80% of total NCS production.

Natural gas exports are almost entirely routed through the NCS pipeline grid system known as Gassled. The total export capacity of Gassled is about 120 billion Sm^3 *per annum*. Three intermediate processing terminals onshore in Norway feed natural gas into the upstream export offtake system for natural gas: Nyhamna; Sture; and Kårstø. Six ultimate receiving pipeline terminals, forming an integral part of the Norwegian hydrocarbons production system that includes Gassled, the natural gas pipeline system, are located on land in Germany, Belgium, France and the UK.

Norway has only one large-scale LNG production project. The Snøhvit LNG liquefaction facilities are located at Melkøya in Northern Norway. Liquefaction is still limited to a single train, currently operating at 90% of the design capacity, exporting some 3.8 million tons (6.1 billion Sm^3) of LNG annually. In addition, there are some small-scale LNG facilities located in the south west of the country serving the local market.

Except for some minor LNG storage, there are no onshore natural gas storage facilities in Norway. Natural gas may be temporarily reinjected and stored into reservoirs offshore. Natural gas reinjections form a core component of the Norwegian resource management philosophy and central part of systematic IOR/EOR activities.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Traditionally, both oil and natural gas have been used for offshore production purposes, but there is considerable political pressure to supply new offshore development projects with electricity generated from onshore hydro power plants.

Norway has abundant hydropower resources, as well as substantial electricity generating, transmission and distribution capacity. Hydroelectric power projects continue to meet most of Norway's energy needs, particularly in sectors other than transportation.

Only around 1.5% of the NCS natural gas production was delivered for domestic market use in 2015.

Natural gas (LNG) is, however, also being increasingly used in the heavier segment of the transport sectors (urban area mass communication, coastal shipping and offshore supply).

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

All of Norway's natural gas requirements may be met by NCS natural gas production.

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1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

98.5% of the NCS natural gas production was exported in 2015. Most of the natural gas production was sold and delivered to the European market. In 2015, the largest volumes continued to be delivered to the UK, Belgium and France. Norwegian natural gas volumes account for at least 20% of total European natural gas consumption.

The Norwegian Petroleum Directorate (NPD) reports the following volumes for natural gas exports in 2015 (first landed in): Germany (42.3%); United Kingdom (24.5%); France (1%); Belgium (14.1%); and Denmark (0.4%).

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Norway has for many years been a major European oil producer and exporter, with the largest estimated oil reserves in Western Europe. Remaining recoverable reserves (liquid petroleum) estimated by the NPD is 3.57 billion Sm^3o.e. (of which 3.14 billion Sm^3 is crude oil). The reserve replacement ratio is slowly decreasing and remaining virgin areas of the NCS are believed to predominantly contain gas reserves.

Total liquid production (crude oil, NGL and condensates) in 2016 was 116.06 million Sm^3o.e.

Mainland Norway is predominantly base rock and there have been no commercial onshore oil discoveries or production to date. Oil produced offshore is shipped by vessels directly from offshore installations to market by ship or landed through pipelines to onshore terminals for final processing in Norway or the UK before being sold to the international market.

Norway has limited domestic refining capacity with only two refineries, as domestic consumption of products is limited and thus most liquids production is exported.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Most NCS production is exported and less than 20% is domestic consumption. Almost all of this is used for road transport (with minor volumes utilised for coastal shipping and offshore supply).

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

All of Norway's oil consumption requirements may be met by NCS production.

2.4 To what extent is your jurisdiction's oil production exported?

Since the oil production peak in 2004, the total production has been on a steady decline until 2014. From 2015, there has been a slight increase in production and still approx. 80% of NCS production is exported.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The rights to petroleum resources in the ground are vested in the State.

The upstream sector in Norway is thoroughly regulated. Government extends exclusive and other rights to commercial entities by way of administrative law-based decisions and not through contracts, unless an entity acts on behalf of the State in its commercial capacity. No-one other than the State may undertake petroleum activities without a specific licence and the appropriate appurtenant permits, approvals and consents pursuant to applicable law. Norwegian petroleum policy and legal framework is focused on optimal resource management, rendering long-term benefits for society as a whole, avoiding, limiting and mitigating negative effects to persons, property and the environment while ensuring that the resource rent remains with the resource owner. The main judicial framework is the Petroleum Act of 1996 and the petroleum and safety regulations issued thereunder. Total Government Take is predominantly secured by corporate taxes, petroleum special tax and State direct participation in the individual Production Licences (through SDFI) and indirect participation (through the majority shareholding in Statoil ASA).

This legal framework establishes the Norwegian licensing system and governs all petroleum activities (exploration, development, production, transportation and decommissioning) arising out of petroleum resources and facilities subject to Norwegian jurisdiction.

The main public authorities responsible for upstream petroleum sector regulation are the Ministry of Petroleum and Energy (MPE), the Norwegian Petroleum Directorate (NPD), and the Petroleum Safety Authority (PSA).

A special tax regime for upstream activities was established by the Petroleum Tax Act in 1975. Under this regime "*petroleum activities and related activities*" are subject to a special petroleum tax rate of 54% in addition to the ordinary corporate income tax rate of 24%.

The main fiscal authorities involved are the Ministry of Finance (MFIN) and the Oil Taxation Office (OTO).

The NCS petroleum industry is facing challenges from lower oil and gas prices and a high-cost environment, but very few fiscal regime amendments have been launched by the Government since 1975. The rationale has been that the system is profit-based progressive. No regressive elements are applied. The State also shares a substantial project and price risk with Licensees through paying its way without economic privileges in relation to its direct and indirect participating interest in the upstream sector.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Resources and upstream activities are not governed by the mineral

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law regime, but by a specific Petroleum Law. Downstream transmission and distribution of natural gas is regulated by a separate Natural Gas Law consistent with EU Internal Market rules. Exclusive Production Licences for exploration drilling and production are, pursuant to the Petroleum Law, awarded by the King in Council (cabinet formal decision headed by the King). Production Licences are normally awarded to groups of companies (Licensees) entitling them to an undivided participating interest in an unincorporated joint venture to be established by the Licensees.

The Norwegian system is an administrative law-based concessionary system. Subject to the Production Licence and applicable law, the Licensees are awarded exclusive rights to explore for and produce petroleum within a defined geographical area (stratigraphic delineation is possible).

One Licensee of each Production Licence is appointed as the Operator by the Government. This also applies to Facilities Licences (awarded pursuant to Section 4-3 of the Petroleum Act), except for the Gassled JV where Gassco AS is the System Operator. The Production Licence further establishes a mandatory work programme and stipulates deadlines for its completion.

Production Licences are awarded in two separate rounds/systems: annual awards in mature areas through the Awards in Predefined Areas (APA) rounds; and in biennial awards cycles in less mature areas by way of regular licensing rounds. The obligatory work programmes for APA and regular licensing rounds are normally different, with an emphasis in the APA rounds on scheduled, fast-track exploration and development obligations based on a "do or drop" approach.

Norwegian authorities have established a pre-qualification system. Production Licences will only be awarded to pre-qualified applicants. The pre-qualification process is not regulated in the Petroleum Act, but is established as a practical administrative process related to the licensing procedures. Successful pre-qualification does not give any rights to actually be awarded licences, but establishes that the applicant meets the minimum requirements. The MPE is assisted by the NPD and PSA to test whether the applicants, if awarded a Production Licence, would be sufficiently technically and financially capable of undertaking petroleum activities and their related obligations as Licensees (or as an Operator).

As a condition for the award of the petroleum licence, all Licensees must enter into the Norwegian standard non-negotiable Agreement Concerning Petroleum Activities ("the *Petroleum Agreement*"). The Petroleum Agreement consists of a main part and two enclosures: Enclosure A – the Joint Operating Agreement (JOA); and Enclosure B – the Accounting Agreement. By concluding the Petroleum Agreement (and the JOA), the Licensees establish an unincorporated joint venture where all Licensees are parties (the Operator being one of the Licensees). The Petroleum Agreement cannot be amended without the approval of the Ministry of Petroleum and Energy.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

In addition to Production Licences, so-called "*Reconnaissance Licences*" may be issued for non-exclusive exploration activities such as seismic, EM studies and shallow drilling. The Reconnaissance Licence does not authorise drilling for the purpose of striking petroleum-bearing strata such as an Exploration or Appraisal well. Reconnaissance Licences are mainly issued to seismic companies for multi-client data collection. A Reconnaissance Licence does not give the licensee any preferential rights to be awarded a production licence or any other rights related to any discoveries of petroleum made. All data acquired or produced as a result of or arising out of such reconnaissance activity shall be submitted to the Norwegian Petroleum Directorate. Depending on the nature of the reconnaissance activity, the data is kept confidential for a number of years as stipulated by regulation. After the expiry of this period the data is made available by the NPD to industry and other interested third parties.

For Production Licensees, several additional authorisations are required for a number of petroleum activities, including seismic acquisition, drilling of wells, development, construction, placement and use of facilities, production of petroleum, emissions and discharges, cessation of production and decommissioning of facilities. Common for most licences, permits and approvals is that conditions may be and are regularly imposed.

The main authorisations required for the life cycle of a successful oil or gas production project are: approval of the Plan for Development and Operation (PDO) by the MPE (Parliament for major developments) which is required in order to commence development; Plan for the Placement and Operations of Facilities (PIO) required for submarine (landing or inter-connecting) pipelines or facilities serving several fields or projects; and approval of the Decommissioning Plan required in order to terminate production or cease the use and dispose of facilities.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Section 3-6 of the Petroleum Act allows the State an option, in line with consistent policy, to directly participate in any Production Licence (separate provisions for stand-alone Facilities Licence). The management of the SDFI and Petoro is regulated by the Petroleum Act Chapter 11. State participation through State Direct Financial Interest (SDFI), managed and represented by Petoro AS, holds a proportionate share in a Production Licence (or Facilities Licence) like any other Licensee. The State will normally take a participating interest in areas considered of strategic interest or which are expected to be the most prospective.

Petoro AS acts as a regular Licensee, with some exceptions; e.g. they cannot be an Operator and under EU rules may not participate in certain procurement decisions. Neither SDFI nor Petoro AS applies for a participating interest in any petroleum licence. The State's share is stipulated as part of the award.

The State also indirectly takes a participating interest through its majority shareholding in Statoil ASA. Statoil has to apply like any other company and is not extended any special rights or privileges compared to other applicants. Carrying of State participation was abolished years ago.

The State through SDFI/Petoro has, pursuant to article 23.3 of the standard JOA, a pre-emptive right to any assignment of a participating interest in a Production Licence. To our knowledge, this pre-emption has not been exercised to date. The State pre-emption right does not include indirect transfers such as share sales.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The State derives value from petroleum production in Norway mainly in the following ways:

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1. Petroleum special tax (54% special tax on petroleum production for 2017).
2. Corporate tax from petroleum-producing companies (24% in 2017).
3. State's direct financial interest.
4. Dividends from Statoil ASA (the State holds 67% of the publicly listed company shares).

Royalty on production of petroleum was reduced in the 1990s and finally abolished entirely in early 2000.

An Area Fee is still applicable for production licences once the initial exploration phase has passed, but is structured to motivate the licensees to either actively explore and develop the licence areas or relinquish them. In 2016, the total State revenue from Area Fees was 1.4 billion NOK.

3.6 Are there any restrictions on the export of production?

There are currently no restrictions on the export of petroleum (oil or gas). Restrictions will only likely apply under an embargo established by the UN or EU, as Norway, through the EEA, is integrated into the EU single internal market.

Pursuant to the Petroleum Act, MPE may under certain circumstances instruct the delivery of petroleum produced for national (emergency) consumption needs, but this is not likely with the current export/local consumption ratio.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

No such restrictions apply.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Transfer of the whole or any part of the participating interest in a Production Licence or any other licence to undertake petroleum activities are subject to MPE and Ministry of Finance (MFIN) approval. Further, indirect transfer of interest or participation in the licence is also subject to approval, such as assignment of shareholdings and other ownership shares, which may provide decisive control of a licensee holding a participating interest in a licence. The NPD and PSA will be consulted on the applications of transfer of interests. Approvals may be conditional.

Change of Operator is subject to a separate MPE approval. Thus an approval of a transfer of participating interest in a Production Licence where the transferor is also Operator does not entail approval of the related transfer of operatorship. Change of Operator is also governed by a separate JV process.

The MPE will only permit transfer to a pre-qualified entity (see question 3.2 above). The MPE will evaluate the transferee's potential contribution to the Licence and whether the transferee has the financial strength and technical capabilities sufficient to actively participate in activities going forward. Hence, requirements will be different for an early-phase exploration project compared to a complex development or production project. The MPE may also consider the transferee's previous performance and other objective and relevant criteria such as national security, public order, public health, transportation security, environmental protection, etc.

The MFIN will assess the tax effects of the proposed assignment. The MFIN has, through regulations, established a system whereby an automatic consent, without written confirmation, is given upon submission of an application. The consent is obtained, provided the parties confirm to the MFIN that the transaction meets certain regulatory requirements.

In addition, any transfer of participating interest is subject to the approval of the remaining licensees, but only until the mandatory work obligation stipulated in the Production Licence has been completed.

With regard to State pre-emption rights, please see above under question 3.4.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

According to section 10-7 of the Petroleum Act, the MPE may demand that financial security in favour of the State or third parties' non-contractual liabilities arising out of petroleum activities is provided by a Licensee For group-held companies, this is obligatory resulting in a requirement for the ultimate parent company of the licensee to provide an unlimited parent company guarantee in the standard form prepared by the MPE at the time of the first Licence award. For licensees which are not part of a group, the MPE may require a bank guarantee or similar security. In certain situations where there is no ultimate parent company in a group or the ultimate parent company is legally barred from presenting an unlimited guarantee (applies for certain State-owned oil companies), the MPE may accept alternative guarantees.

The ultimate parent company guarantee is a condition for any Production Licence award, maintenance of rights or assignment. The parent company guarantee is an unlimited, unconditional and irrevocable on-demand guarantee established by a non-negotiable document in Norwegian.

Regardless of the State being the main beneficiary under the guarantee, third parties may under certain conditions and circumstances present claims directly against the guarantor for damage or loss caused by pollution or personal injury which arise out of petroleum activities.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Participating interests in Production Licences or Facilities Licences may be pledged as security, subject to MPE approval. Rights to security of this nature may only be registered in the Norwegian Petroleum Register. This registry is publicly available online.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

For a Production Licence, additional authorisations are required for a number of activities, including seismic collection, drilling of wells, construction, placement or use of facilities, production of petroleum, discharge and emissions, cessation of production and decommissioning, including removal of the facilities. Common for most licences, permits, approvals and consents issued by public authorities is that they regularly entail conditions for approval. Key

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regulatory authorities are the MPE, the Petroleum Directorate, the Petroleum Safety Authority, the Environmental Directorate and the Coastal Waters and Harbour Authority.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Cessation of petroleum activities and the decommissioning of facilities used for petroleum activities may, subject to chapter five of the Petroleum Act (and chapter six of the Petroleum Activities Regulation), only be undertaken subject to an approved Decommissioning Plan. The rules of applicable law incorporate the OSPAR Convention, to which Norway is a party. The MPE, supported by the NPD and the PSA, is the key relevant Government authority for such approvals.

A Decommissioning Plan is a comprehensive study that addresses and evaluates different options for decommissioning, including removal, and also includes a specific comprehensive environmental impact assessment (EIA) addressing, *inter alia*, HSE-relevant components. The EIA is subject to public circulation and comment prior to approval of the Decommissioning Plan.

The assignor of a participating interest in a Licence remains jointly liable with the assignee for relevant decommissioning costs (Petroleum Act section 5-3 third paragraph). This liability is normally mitigated by means of a Decommissioning Security Agreement between the assignor and the assignee.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

There is no specific legal framework for large-scale natural gas storage which otherwise would be regulated by the Petroleum Act or the Natural Gas Act.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

No particular regulatory limitations apply.

Natural gas sales are individually executed by Production Licensees. Many sales are intra-group sales. There is a trend of movement from long-term sales pegged to the oil price, towards shorter-term sales conducted over European hubs.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

No particular regulatory limitations apply.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

The NCS natural gas transportation system is the world's largest offshore natural gas transportation system. It includes several large diameter submarine pipelines, several onshore terminals and processing facilities onshore in Norway, Germany, Belgium, France and the UK.

The facilities are mostly owned by Production Licensees, most of whom have become owners of the transportation facilities as a consequence of their obligation to propose a gas offtake solution as part of any Plan for Development and Operations (PDO). In recent years, purely financial investors, with a petroleum-competent staff at a bare minimum, have also been permitted to acquire participating interests in the natural gas transportation system.

The system referred to is predominantly owned by Gassled, an unincorporated joint venture. Gassled is operated by Gassco AS, a wholly State-owned joint stock company. Gassco is the appointed Gassled System Operator.

Gassco manages capacity bookings and capacity allocation. MPE has issued regulations stipulating conditions for access and tariffs to be paid to Gassled.

All shippers with a duly substantiated need for capacity shall have access to Gassled on a non-discriminatory, objective and transparent basis. Tariffs are based on booked capacity, not throughput.

The State amended the tariff regulations in June 2013 and thereby reduced the transportation tariff by 90%, for volumes transported after 1 October 2016, citing the need for readjustment to the utility rate of return as initial investments in facilities had been recovered. Financial investors, having been assignees of participating interests in Gassled in later years, have initiated litigation against the State. The Borgarting Court of Appeal's decision of 30 June 2017, ruling in favour of the State, has been appealed to the Supreme Court. Whether the appeal will be admitted to the Supreme Court will have to be determined by the Supreme Court Appeals Selection Committee.

Norway has several transportation pipelines carrying liquids to onshore landing at processing facilities, including at Sture, Mongstad and Kårstø in Norway. There is also one oil export pipeline going to the UK. Pipelines carrying liquids are not part of the Gassled system and are all owned by Production Licensees, normally proportionate to their shipping needs.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The construction, placement and operation of a pipelines for transportation of petroleum may only be carried out pursuant to an approved Plan for Development and Operation (PDO) (see question 3.3 above), or alternatively pursuant to a separate or subsequent Plan for Installation and Operation of Facilities (PIO). Approval of such plans is made by the MPE supported by the NPD, PSA and the Environment Directorate.

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6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Land use onshore for terminals or pipelines is limited. Onshore processing plants form an integral part of production projects, including those requiring large diameter submarine pipelines for export of natural gas to Europe. Acquisition of land or land rights are to be agreed with landowners. If no agreement is reached, compulsory acquisition of land (expropriation) pursuant to mandatory applicable law is available.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Please see the general comments above in question 6.1.

Gassled shipping capacity is booked through Gassco AS, acting as the System Operator.

Second-hand trade in capacity available is permitted under a regulated system and may be acquired from shippers with spare capacity.

Access to liquids transportation systems is subject to the rules of the Third Party Access regulation, and is negotiated directly with the facilities' owners based on regulated terms.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The natural gas transportation system is highly integrated with offshore production facilities directly tied into the gas-gathering system at several points. When allowing natural gas from a new development into the pipeline landing system, a thorough analysis of capacity is required, and gas specifications are carefully evaluated to ensure that input into and output from the system remains according to the specifications required.

Cooperation between facility owners is handled by the Gassled JV agreement and between the shippers through the Gassco booking and shipping manuals.

Pipelines for liquids transportation are not integrated in the same way. Any cooperation required is handled by the respective facilities' owners directly pursuant to applicable law, conditions for the approval of the PIO, and terms and tariffs approved.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Third-party access to Gassled is governed by regulations to the Petroleum Act. Gassled is open to all qualified shippers of natural gas on a non-discriminatory basis.

Access to all other facilities for use in Petroleum Activities, other than Gassled, is governed by the Third Party Access Regulation. The regulation sets out the main principles for access, tariffs and other terms or conditions. The main principle for cost allocation for modifications required to allow additional volumes access shall be agreed between parties. The principle that transportation facilities shall not yield profit beyond a utility rate of return on capital and operational costs must be adhered to. Where a tie-in to existing facilities adds value to the host facility, the owners of such facility must, under this principle, be prepared to pay a relative share of associated costs. TPA agreements require MPE and NPD approval, if not otherwise decided. If the parties cannot agree on an access tariff agreement, the matter may be submitted to the MPE for final decision.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Gassco/Gassled terms and tariffs are stipulated in accordance with regulations.

For facilities that are not part of Gassled, the parties are free to negotiate, within the limitations set out in the TPA regulations, and any specific PDO or PIO conditions for approval, and agreements relating to the facilities in question (e.g. the Oseberg Transportation System).

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Norway's consumption of natural gas is minimal and limited to minor locally operated onshore natural gas distribution networks.

There are currently no Government initiatives aimed at expanding natural gas transmission, distribution or use.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

By delegation from the MPE, a concession for the establishment of a network must be obtained from the Norwegian Water Resources and Energy Directorate. Land rights must be obtained from landowners, while construction permits and environmental permits must be obtained from other competent authorities.

7.3 How is access to the natural gas distribution network organised?

Access to natural gas networks is subject to negotiation with the system owner and Operator. Access is subject to applicable law to be on non-discriminatory terms and conditions consistent with EU internal market requirements.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

There are currently no provisions to enforce this.

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7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Fees have to be non-discriminatory, allowing the system owner only a modest rate of return on investment and operational costs (often referred to as the utility rate of return), but are otherwise not regulated and subject to negotiations with the owner or Operator.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Only companies may receive a concession to construct, own or operate a natural gas utility. No other particular restrictions in law apply, but limitations may be stipulated in each concession. If a natural gas utility also holds a participating interest in Production Licences, then acquisition of an interest that provides or changes the control of the utility will trigger the requirement for MPE approval pursuant to the Petroleum Act section 10-12.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

All natural gas produced from NCS resources is sold by Production Licensees individually, under negotiated gas sales agreements.

Most volumes are delivered under long-term take-or-pay contracts, but volumes are increasingly traded on shorter short-term contracts over European hubs.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

There are currently no legal restrictions on trading volumes of natural gas. Bundling of goods and services in the energy sectors is subject to Norwegian rules, which are consummate with EU internal market rules.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

The main Norwegian LNG production facility, at Melkøya in Finnmark, forms an integral part of the Snøhvit production project and is owned by the Snøhvit Licensees. Production of LNG is, in this case, considered an integral part of upstream petroleum activities and subjected to the Petroleum Act from the source until the LNG is loaded onto an LNG tanker.

Small-scale LNG plants in Norway purchase their natural gas as a commodity from NCS Licensees. LNG regasification plants are regulated as downstream activities and governed by the Natural Gas Act.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

If LNG facilities are deemed part of the upstream production project, then they are subject to the same PDO requirement (may be combined with a PIO) and requires further authorisations for construction, operation and decommissioning as described above in question 3.2.

For LNG facilities subject to the natural Gas Act, a concession must be obtained from the Water Resources and Energy Directorate, as per delegation by the MPE. Permits from land use and environmental authorities are also required.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Norway currently has no specific regulations of the price, terms or conditions for service in the LNG sector. See above regarding terms and conditions for access to facilities.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

LNG facilities that form an integral part of upstream petroleum production are subject to the Third Party Access regulations as addressed above.

Downstream LNG facilities are not subject to these provisions and any third-party access will have to be negotiated. See above for the downstream natural gas regime regulated by the Natural Gas Act and appurtenant downstream regulations.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The Norwegian downstream oil sector (petroleum products) is market-based and is not heavily regulated.

Safety and environmental regulations that apply to refining and distribution are of key importance. EU rules concerning safety and product marking have been implemented in Norwegian law. Certain provisions still in place apply with regard to emergency supply and stock in case of national emergencies. These requirements have, however, been dramatically reduced.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Oil trading is liberalised and is left to the producers, shippers or traders. Many smaller producers elect to have their oil sold by companies trading larger volumes. As a consequence, large NCS Operators, like Statoil, sell oil on behalf of other Licensees, in addition to their own production. Statoil also markets and sells the oil of the State's Direct Financial Interest, the participating interest in which is otherwise managed by Petoro AS. This makes Statoil by far the largest seller of NCS oil.

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11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The Norwegian Competition Authority (NCA) is the competent national competition authority also for the oil and gas sector. In addition, Norway and NCS Licensees are subject to the EU internal market rules by way of the EEA and thus, in the case of competition, the jurisdiction of the European Commission or the EFTA Surveillance Authority (ESA) and related community courts.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Norwegian competition law mirrors, to a large extent, EU competition law and applies the same concepts and criteria prohibiting anti-competitive practices. Unilateral conduct and merger control rules may deviate from the Commission's case law.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

In Norway, the NCA has powers comparable to those of the European Commission/EFTA Surveillance Authority under EU/EEA competition law, including the authority to issue cease-and-desist orders, the imposition of fines and blocking of mergers.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

The Norwegian Competition Authority exercises control with Norwegian oil and gas mergers that do not have an EU/EEA dimension. Deals that do not meet the thresholds of the European Merger Regulation will thus be subject to national merger control, provided that the national turnover thresholds are fulfilled.

Norwegian merger control is based on a notification system and subject to economic thresholds similar to the EU, with set deadlines for the authorities to initiate extended investigations (15 working days from notification) or intervene (100 working days from notification).

NCA decisions in merger control cases may be appealed to the Ministry of Government Administration. Any administrative law-based decision in Norway may be subject to limited judicial review by the courts.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

No specific limitations apply in Norway. Control with acquisitions is exercised pursuant to the rules of the Petroleum Act section 10-12. The approval procedure is based on Government administrative law discretionary power, and on non-discriminatory criteria such as financial strength and technical competence. Recent case law indicates that a reciprocity principle may be applied with regard to acquisition of a participating interest in or control over an entity that holds a participating interest in Production Licences. Proposed amendments to the Petroleum Regulations, presently subject to circulation and public hearing regarding future rules on assessment of applicants during licensing rounds and assignment, or participating interests in petroleum licences, may indicate that the MPE wishes to apply stricter requirements than previously in the years to come.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The regulatory environment is substantially influenced by multinational conventions such as UNCLOS, EEA, the OSPAR Convention and several bilateral treaties such as the transboundary fields or submarine pipelines treaties.

Norwegian laws are substantially affected by the development of EU rules and regulations. In a number of areas, Norwegian law is more developed than international rules and in most cases functionally rather than prescriptively structured.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

There are no compulsory oil and gas-specific dispute resolution mechanisms for investor-State or inter-Licensee relationships in Norway. All administrative acts by authorities (upstream or downstream) are governed by Norwegian law and subject to the ordinary Norwegian courts, unless otherwise approved by Government. According to concessionary terms, all contracts related to or arising out of a Production Licence or Facilities Licence shall be subject to Norwegian law. Downstream there has to date not been stipulated any mandatory governing law for contracts save for that contracts for the supply of products to consumers is subject to mandatory Norwegian consumer protection law.

It is quite common in construction or contracts for the provision goods and services, as well as sales of oil and gas (commodities) contracts, to agree arbitration with forum in Stavanger, Norway, based on the Norwegian Arbitration Act (UNCITRAL Model Law) as applicable procedural rules for the arbitration.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Norway has ratified both conventions.

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13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

In cases submitted to the ordinary Norwegian courts, there are no particular difficulties in this regard, even where Government is a party.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

Major disputes between Upstream Petroleum Licences and the State have almost without exception been submitted to the ordinary courts of Norway. Foreign corporations have tried several cases against the Norwegian petroleum and petroleum taxation authorities over the years; several were lost and some won:

1. The Ekofisk Royalty Case. Production Licensees successfully challenged the application of amended royalty terms introduced in 1972 against the State (MPE) before the Norwegian Supreme Court.
2. Tax cases: A significant number of income tax cases have been successfully fought against the Government (Ministry of Finance/Oil Taxation Office). However, the Licensees have also lost in several cases.
3. The Gassled Case: Following the approval of assignments of participating interests in Gassled from upstream NCS Production Licensees to NCS non-operating investors, the Ministry of Petroleum in 2014 passed a Decree amending the Gassled Tariff Regulation of 2002, reducing the capital element of the transportation tariff for future bookings in the Gassled pipeline system by close 90%. Following this, the investors in Gassled which were not gas shippers initiated court proceedings against the Government, claiming that the amendments to the Tariff Regulation of 2002 were illegal. Principally they claimed the amendments lacked proper legal basis; if legal basis were found by the court to be established, then the amended rules amounted to illegal retroactive effect of law or administrative decisions, alternatively the amendment was a breach of contract as tariffs had been agreed between the Government and Gassled owners at the establishment of Gassled in 2002, or finally an amendment of this nature was in breach of Norway's obligation to protect private property under the European Convention of Human Rights Protocol 1. The investors also claimed that even if the court found legal grounds for amendment to be present, the conduct of the Ministry of Petroleum and Energy was negligent in its implementation and on all of these grounds, investors claimed compensation for their future economic losses. The District Court ruled against the investors, as did the Court of Appeal on 30 June 2017. The District Court found the investors had reason to raise a case due to lack of clarity and thus did not award the defendant legal costs. The Court of Appeal reversed this decision and awarded legal cost to the Government.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Norway has a mature oil and gas regulatory environment. Norway's upstream and downstream regulatory regime has evolved stepwise over time. It has to date been considered highly stable and is still considered predictable even with regard to tax and fiscal terms. It is a matter of Government policy to keep the regime relatively stable and at all times predictable.

A sudden change of Petroleum Tax regime with regard to a reduction in the Uplift deductible before petroleum special tax a few years back caused a stir in the petroleum community, as it was highly unexpected and one of the first times since the special petroleum tax was introduced in 1975 that amendments to the tax law were not entirely balanced or definitely in favour of Licensees. Political calls for less polluting petroleum production have resulted in requirements imposed in PDOs for mandatory hydroelectric power supply for some new offshore installations. Against the Government's recommendations, the Norwegian Parliament decided that the new offshore installations to be constructed and placed at Utsira High shall be powered by electricity generated by onshore hydropower projects. This was an expensive solution that the upstream industry viewed as having questionable environmental effects.

Despite political calls for a "*green shift*" away from a petroleum-based economy, all major political parties seem to appreciate the value of a predictable and stable regulatory and fiscal system maintained in order to attract investments in the NCS. Parts of the NCS which cannot offer good prospects or low costs have been countered by, *inter alia*, regulatory predictability and exploration risk mitigation through the exploration costs cash-back system and the substantial sharing of risk associated with State participation without carry or other economic privileges.

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Mr. Leerberg's practice focuses on Norwegian and international oil & gas transactions, governance, administration and negotiation of petroleum rights, business and public administrative law and public international law. He also has extensive experience from Government and private practice on introducing and establishing presence and activities in the Norwegian continental shelf (NCS) industry.

He has extensive experience with host nation governance of natural resources, development of legal and contractual regimes and legal aspects related to the establishment and management of NCS licensees, facilities and related petroleum activities. He advises, on an ongoing basis, several energy administrations, national oil companies, international organisations and commercial companies.

His comprehensive oil & gas experience extends over more than 25 years and includes practice as a private practitioner, senior civil servant and lecturer. After joining Simonsen Vogt Wiig in 2003, he has been building its NCS and upstream international energy team. Clients include several upstream petroleum and energy companies, as well as Government and international organisations with activities located on four continents.

Mr. Leerberg has been a guest lecturer at University of Trondheim (1994–98), and lectures at the International Programme for Petroleum Management and Administration (PETRAD) (1994–2017), having participated in PETRAD activities in 18 countries, and with the Norwegian School of Business Executive Masters in Energy Administration programme (2007–), including its international collaboration programmes.

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Mr. Vareberg specialises in petroleum and energy law issues. He assists clients in the Norwegian oil & gas sector and internationally, both on regulatory and contractual issues in relation to energy and petroleum activities offshore and onshore. He has more than 17 years of working experience with petroleum law and has in-depth knowledge of the Norwegian petroleum policy, legislation and practice. Mr. Vareberg has worked as a Senior Advisor in the Norwegian Ministry of Petroleum and Energy and as Head Negotiator in the Norwegian Shipowners' Association. He has assisted clients in the petroleum and energy business as a lawyer in SVW for more than seven years.

He assists a number of Norwegian and international oil companies in Norway, in areas such as: entering strategy; pre-qualification process; licence applications; joint-venture issues; transfer of production licences; corporate transactions and assignments; petroleum law and licence issues; and negotiations with partners and government relations. He also assists several Norwegian government entities within the petroleum sector, such as Gassco AS (the Norwegian natural gas transportation network operator), the Norwegian Petroleum Directorate and the Norwegian Safety Authority, on petroleum law and HSE matters. He regularly holds presentations and lectures on petroleum law issues and is also an external examiner in petroleum law at the University of Oslo.

Mr. Vareberg has extensive experience from international oil & gas projects, consulting national governments and national oil companies in Europe, Africa and the Middle East on petroleum policy, organisation, development of petroleum legislation, negotiations and management of licence agreements, concession contracts, production-sharing agreements, joint operating agreements, accounting agreements and related contracts. Mr. Vareberg has been involved in the development of petroleum law, regulation and contractual regimes in Lebanon, Montenegro, Uganda, Timor-Leste, Sudan and Mozambique. In Mozambique, Mr. Vareberg was part of the core legal team preparing the revised petroleum law and regulations, and negotiating the regulatory and contractual legal framework for the Rovuma Basin natural gas discoveries – some of the largest natural gas discoveries in the world.

He has worked on the development and operation of some of the largest wind power projects in Norway. Further, he is presently a key advisor to Gassnova SF (the Norwegian government entity with responsibility for CO2) in the current Norwegian pilot project of establishing a full-scale CCS-chain (capture, transport and storage of CO2) on the NCS.

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Simonsen Vogt Wiig is a leading business law firm with offices in Norway's largest cities, as well as in Singapore. Our 180+ lawyers provide assistance within all major business sectors, building lasting relationships with clients by combining thorough business understanding with top legal expertise.

We have one of Norway's most extensive and internationally oriented Oil and Gas practice groups. Having been involved in the Norwegian oil sector from its inception through today's industry turmoil, SVW offers one of the most respected consulting environments, particularly through our offices in Oslo, Stavanger, Bergen and Kristiansand.

Our team background ranges from in-house legal positions with international operators, to civil servants with the Ministry of Petroleum and Energy. Our team's diverse experience and profound expertise is invaluable in the provision of legal and consulting services to our clients, ranging from international and national oil and service companies to Governments on all continents, and inter-governmental organisations.

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Portugal

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Portugal does not have any natural gas reserves. All the natural gas consumed in the country is imported, mainly from Algeria, Qatar and Nigeria. Nonetheless, natural gas plays an important role in the country's energy mix, having accounted for 18% of the primary energy use during the year of 2015.

Natural gas is imported into the country either by pipeline (connected to Spain), which in 2016 received two-thirds of the natural gas consumed in the country, or through the Sines LNG Terminal, the entry point of the remaining one-third. The Terminal is equipped to carry out reception, storage and re-gasification of hydrocarbons, and is also connected to the national gas network. The Terminal was constructed in 2004 and its capacity was increased in 2009.

The importation of natural gas into the country had systematically and gradually decreased since 2011. However, 2016 witnessed a contrary development as natural gas imports increased, unlike the importation of oil and coal which continued their downward trend. Concerning the present year, provisional data shows that the importation of natural gas continued to increase and, similarly, the importation of oil and coal continued to decrease. During 2017, natural gas was heavily relied upon for energy generation, compensating not only for a decrease in the consumption of oil and coal but also for a drop in energy produced from renewable sources in general, particularly attributable to the significant decline in hydroelectric generation.

The principal legal instruments for the natural gas sector are Decree-Law no. 30/2006 of 15 February 2006 (hereinafter "**DL 30/2006**") and Decree-Law no. 140/2006 of 26 July 2016 (hereinafter "**DL 140/2006**"), which establish and regulate the Natural Gas National System (*Sistema Nacional de Gás Natural*) as well as the activities of transport, storage, distribution and trading.

From a regulatory standpoint, the major agents in the LNG industry are: (*i*) the Energy Services Regulatory Authority (*Entidade Reguladora dos Serviços Energéticos* – hereinafter "**ERSE**"), which oversees the LNG market, as well as activities such as regasification and underground storage; and (*ii*) the General Directorate for Geology and Energy (*Direcção-Geral da Geologia e Energia* – hereinafter "**DGEG**"), which monitors the safety of supplying activities, licensing infrastructure and LNG networks, pipelines and other storage or regasification facilities.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Natural gas accounted for 19.9% of the primary energy supply in 2016.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Portugal does not produce any natural gas.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Portugal does not export natural gas.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Despite exploration activities being conducted in Portugal since the 1940s, no commercially viable deposits of oil have been found. Nevertheless, exploration activities in the country's EEZ continue, motivated by: (*i*) Portugal's proximity to North Africa which is known to have significant oil reserves; (*ii*) the extension of the nation's offshore territory; and (*iii*) the quality of the infrastructure, in particular the Sines Terminal. Most of the current exploration activity is around the Lusitânica Basin in the centre of the country. But there is also some activity in the south, around the coast of Algarve, led by companies such as Partex, Repsol and ENI, the latter of which recently obtained a licence to conduct deep offshore exploration activities off the coast of Alentejo, in a consortium also integrated by Galp, the major Portuguese oil company.

From a regulatory standpoint, the main agents are DGEG and the National Authority for the Fuel Market ("*Entidade Nacional para o Mercado de Combustíves*" – hereinafter "**ENMC**") with competence over the constitution, management and maintenance of crude oil reserves and petroleum products. ENMC was created by Decree-Law no. 165/2013 of 16 December 2013 (hereinafter "**DL 165/2013**") which transposed the European Council Directive 2009/119/CE.

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The most important single player in the oil sector is Galp, having originated from the merger of Petrogal, which refined and distributed petroleum products, with Gás de Portugal, which was an importer and distributor of natural gas.

Currently, Galp is a fully integrated oil company, with significant upstream, midstream and downstream activities, from production and exploration, to refining and distribution. Galp's upstream activities are predominantly located in Brazil, Angola and Mozambique; regarding midstream and downstream, Galp operates the only two refineries in the country and distributes petroleum products in Portugal, Spain and some African nations.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Oil accounted for 42.7% of the primary energy supply in 2016.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Portugal does not produce any oil.

2.4 To what extent is your jurisdiction's oil production exported?

This is not applicable in our jurisdiction.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Exploration and production of petroleum is regulated by Decree-Law no. 109/94 of 26 April 1994 (hereinafter "**DL 109/94**"). The aforementioned statute establishes that petroleum deposits are part of the public domain of the State. Exploration and production activities may be exercised by any entity with the required technical and financial capabilities and upon the grant of a concession (s. 5.1 DL 109/94). Concessions are granted by the government, through the Ministry of Energy (s. 6.1 DL 109/94), and are preceded by a public tender but may also, in special circumstances, be awarded directly.

The statute also provides for the possibility of applying for a Previous Assessment Licence ("*Licença de avaliação prévia*" – hereinafter "**PAL**"), a preliminary procedure which may be executed before the concession is granted. Under the PAL, licensees may process and evaluate information available in ENMC's archive as well as collect surface samples and conduct surveying activities in order to assess the potential of the licensed areas. The PAL is awarded by ENMC (ss. 5.2 and 23.1 of DL 109/94).

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The State's mineral rights are transferred to investors or companies through a concession agreement. The general terms of the concession are enshrined in DL 109/94 and in Ordinance no. 790/1994 of 5 September 1994 (art. 18 DL 109/94). In accordance with DL 109/94, the concession contract is of an administrative nature (s. 18).

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Further to the PAL, the concession agreement encompasses both exploration and production activities, as follows:

1. Exploration (*prospecção e pesquisa*): Any laboratory or field activity conducted for the purposes of finding or assessing petroleum deposits are deemed to be exploration activities (s. 30 DL 109/94). The exploration phase is to last for eight years (s. 35.1 DL 109/94), although this period is extendable for two consecutive one-year periods, if the concessionaire does not complete the work programme during the first eight years due to a valid reason. The concessionaire is bound to regularly survey the area under the concession, in accordance with the annual work programmes which are part of the agreement. Such work programmes will bind the concessionaire to carry out surveying activities in at least one block per year, from the third year of concession onwards (s. 35.2 DL 109/94). During the exploration period, the concessionaire is also subject to a relinquishment obligation which will apply at the end of the first five years of concession, according to which the concessionaire shall relinquish at least 50% of the initial area (s. 36.1 DL 109/94). If by the end of the first eight years the concessionaire wishes to extend the exploration period, in order to do so, 50% of the area still under the concession has to be relinquished (s. 36.2 DL 109/94).
2. Development: If, during the exploration phase, a concessionaire discovers an economically feasible petroleum deposit, the subsequent phase is development. In this phase the concessionaire will prepare a general work programme for the development and production of such deposit (s. 37.1 DL 109/94). The general programme will have to be submitted and approved by the ENMC and shall include *inter alia* the following information: (*i*) technical description of the petroleum to be produced; (*ii*) blueprint of the location of the petroleum as well as the infrastructure to be installed; (*iii*) investment programme; and (*iv*) forecast of the date on which commercial production is expected to begin as well as the progress of production levels in the field (s. 38 DL 109/94).
3. Production: Commercial production may begin as soon as the respective programme is approved. The production phase will initially last for 25 years, although it may be extended one or more times up to a maximum period of 15 years (ss. 23.3 and 23.5 DL 109/94). The concessionaire is bound to measure and register all the petroleum extracted and recovered on a daily basis (s. 43 DL 109/94). The construction or installation of any pipelines, storage facilities and other related infrastructure is subject to the approval of the Ministry of Energy (s. 45.1 DL 109/94).

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

The State does not have any ownership interest or seek to participate in the activities of concessionaires *per se*. However, as mentioned, petroleum deposits are deemed to be public domain (s. 4 DL 109/94).

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3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The State obtains revenue from petroleum operations from taxes and other fees payable by concessionaires. Oil and gas operators in the country are subject to the general tax regime and also to a petroleum income tax. We summarise below the main taxes and fees applicable:

1. Royalty: A progressive tax based indexed to factors such as location (onshore/offshore) and annual production (s. 51.1 DL 109/94).
2. Income tax: Tax on the profits generated by the concessionaire.
3. Surface fee: Fee calculated in accordance with the value attributed to each square kilometre of the land under the concession. The fee is paid annually (ss. 52 and 53.1 DL 109/94).

DL 109/94 also sets out licence issuance fees, agreement signature fees and assignment of contractual position fees (s. 54.1 DL 109/94 and Oder (*Despacho*) no. 82/94 of 24 August 1994).

3.6 Are there any restrictions on the export of production?

There are no legal restrictions on the exportation of production nor any obligation to supply the domestic market. The general rule under DL 109/94 is that the concessionaire may freely dispose of the hydrocarbons produced as it wishes, subject to the caveat that the State may, upon a resolution of the Council of Ministers, request that part or all the petroleum produced is used to supply the domestic market, in the event of war or other emergency, and in accordance with the strategic needs of the country (ss. 78 and 72 DL 109/94).

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

The European Union principle of the free movement of capital applies in Portugal – there are no restrictions of this sort.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Assignment of the concessionaire's contractual position is subject to the approval of the Energy Ministry, and a transfer of more than 50% of the share capital of the concessionaire is also subject to the aforementioned Ministry's approval (s. 77 DL 109/94). An assignment fee will also be payable (s. 54.1(c) DL 109/94).

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Yes. In the terms of DL 109/94, one of the requirements of any interested party to participate in a public tender will be to provide a guarantee (s. 11.4(c) DL 109/94); such guarantee is provisional, i.e. it is not meant to last for more than one year and is merely intended to secure the proposal submitted in the public tender (ss. 74.1 and 74.2 DL 109/94).

Besides the aforementioned interim guarantee, concessionaires are also required to provide another guarantee covering the performance of the obligations arising out of the licence or the concession agreement, as well as damage caused to the State or to third parties (s. 74.4 DL 109/94). Such guarantee shall amount to 50% of the programmed works and shall last throughout the period of the concession and 60 days thereafter (s. 74.5 DL 109/94).

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The possibility to pledge or otherwise encumber rights acquired under a concession agreement of this type is not expressly regulated by DL 109/94. However, according to art. 688.1(d) of the Portuguese Civil Code, rights arising out of concessions of the public domain may be subject to a mortgage, although the legal rules on the transfer of such rights have to be observed.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Additional permits may be necessary in addition to the concession. Depending on the permit sought, different authorities will have to be consulted.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

There is no particular legal instrument pertaining to decommissioning; nevertheless, DL 109/94 regulates, in very general and brief terms, decommissioning activities.

Concessionaires may relinquish any part of the concession on grounds of lack of financial or technical feasibility (s. 48.1 DL 109/94).

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

Yes. The two most important statutes concerning gas storage are Decree-Law no. 30/2006 of 15 February 2006 (hereinafter "**DL 30/2006**") and Decree-Law no. 140/2006 of 26 July 2006 (hereinafter "**DL 140/2006**"). Gas storage is one of the components of the National Transport, Infrastructure, Storage and LNG Terminal Network (*Rede Nacional de Transporte, Infraestrutura de Armazenamento e Terminais GNL* – hereinafter "**RNTIAT**").

In accordance with DL 30/2006, which established the general principles on the organisation and functioning of the National System of Natural Gas, gas storage (including both underground storage and LNG terminal storage) is operated under a concession regime (s. 15.1 DL 30/2006); such concession follows either a public tender or a restricted tender with a pre-qualification stage (s. 15.2 DL 30/2006). Operators (concessionaires) of an underground storage facility or an LNG terminal are legally independent from all other entities which, directly or indirectly, carry out other activities in the natural gas value chain. Such operators are also statutorily barred from holding stakes, directly or through a subsidiary, in companies which produce or sell natural gas (ss. 20.1, 20.2 and

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20.3(e) DL 30/2006). Operators of an underground storage facility cannot purchase gas for resale (s. 19.4 DL 30/2006).

DL 140/2006 describes the underground storage of natural gas as an activity which includes *inter alia*: acceptance, storage, extraction, treatment and delivery of natural gas, both for the constitution of reserves and for operational and commercial purposes; and the construction, maintenance and operation of all infrastructure related thereto (s. 16.2 DL 140/2006). Similarly, LNG terminal storage includes: acceptance, storage, treatment and regasification of LNG; loading (onto tanker trucks or LNG vessels); and the construction, maintenance and operation of related infrastructure (s. 18.2 DL 140/2006).

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Entities which sell natural gas are subject to registration (s. 33 DL 140/2006); however, such entities have the right to trade natural gas either through bilateral agreements or on organised markets and, most importantly, the right to freely negotiate the terms and conditions of such sales with their clients (s. 35.1 DL 14/2006).

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

The sale of oil and oil products is not subject to any independent licensing procedure, although ENMC will have to certify both the facilities and the market operator (s. 19 of Decree-Law no. 244/2015 of 19 October 2015 – hereinafter "**DL 244/2015**"). Sale of oil and oil products to EU Member States, both at the wholesale and retail levels, is permitted as long as the tax and customs obligations are complied with (s. 21 DL 244/2015).

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Natural gas comes into the country through a pipeline at the border with Spain. The pipelines which make up the National Natural Gas Transport Network transport the hydrocarbons to the smaller networks operated by the different distribution companies. Natural gas is stored underground inside saline aquifers.

Alternatively, the other point of entry for LNG is the Sines Terminal, which receives and stores the LNG up to the point of regasification; after regasification, the hydrocarbons are directly pumped into the pipelines which connect the Sines Terminal to the National Network.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

As briefly described in question 3.13 above, any activity which integrates the RNTIAT may be carried out through a concession (s. 15.1 DL 30/2006). The notion of transportation of natural gas includes acceptance, transport and delivery through high-pressure networks, and the construction, maintenance and operation of all related infrastructure (s. 14.3 DL 140/2006).

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Concessionaires have the right to request servitudes and even the expropriation of immovable property necessary for the construction of infrastructure deemed to be necessary to the concession (s. 8.1(b) DL 140/2006). However, such concessionaires are also bound to pay any due compensation which may arise (s. 9.3(e) DL 140/2006).

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Access to the public networks of natural gas distribution is granted by a concession or licence. Further, RNTIAT operators are bound *inter alia* to ensure the access of third parties to the network in a non-discriminatory and transparent manner (s. 13.5(e) DL 140/2006).

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Oil pipelines are not integrated, while natural gas pipelines are, as referred above, interconnected.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

One of the statutory duties of RNTIAT operators is to adequately plan and ensure the expansion and technical management of the national distribution network in order to ensure third-party access. This general rule of granting third parties access to infrastructure applies not only in distribution, but also to other storage and transport facilities.

However, this general principle does not apply to closed networks (defined as a distribution network which distributes natural gas within an industrial or commercial location, or within a geographically limited location excluded from the concessions and licences granted

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for natural gas distribution), whereby the owners and operators freely agree on the rates (ss. 28.1 and 29.6 DL 140/2006); however, if the third party does not agree with the rates or practices of a closed network, a complaint may be made to ERSE which will establish a fair rate to be applied (s. 28.7 DL 140/2006).

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

The regime differs between natural gas and oil.

Third-party access to oil storage and transport infrastructure is regulated by DL 244/2015, according to which the owners of pipelines or storage facilities which are in the public interest have to allow third-party access to them, through an agreement, negotiated in a non-discriminatory and transparent manner (s. 24.1 DL 244/2015). In this context, owners of this sort of infrastructure are statutorily bound to: (*i*) inform ENMC of the prices agreed upon within 30 days; (*ii*) submit an annual price rate plan on the price method to be applied the following year; and (*iii*) regularly publish and update the capacity of their infrastructure (s. 24.2 DL 244/2015).

Conversely, concerning access to public natural gas infrastructure, the Regulation on the Access to Networks, Infrastructure and Interconnections of the Natural Gas Sector (hereinafter "**RANI**") establishes that the fee payable for accessing such infrastructure is regulated by ERSE in the Tariff Regulation (s. 15 RANI).

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

For the purposes of DL 140/2006, distribution encompasses: (*i*) the receipt and delivery of natural gas to final customers through medium- and low-pressure networks; (*ii*) the receipt, storage and regasification of LNG, its transportation and delivery to final customers; and (*iii*) the construction, maintenance and operation of all infrastructure related thereto (s. 20.2 DL 140/2006).

Distribution may thus be carried out through a regional distribution concession or a local distribution licence. The latter will be issued in territorial areas which are not covered by the regional concessions (s. 22.1 DL 140/2006) and cover the distribution of natural gas and the receipt, storage and regasification in autonomous units connected to the licensee's respective network (s. 23.2 DL 140/2006). Concessions are awarded for a maximum period of 40 years, while licences may only be awarded for a maximum of 20 years (s. 26 DL 140/2006).

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

The authorisations are either the concessions or the licences.

7.3 How is access to the natural gas distribution network organised?

The RANI establishes that access to the natural gas distribution network is obtained through a contract entered into between the interested party and the operator of the network. The general terms of such contract are subject to regulation by ERSE (s. 10.1 RANI) and are entered into for a maximum period of one year, between 00:00 on October 1st and 24:00 of September 30th of the following year. These agreements are automatically renewable for successive one-year periods (ss. 11.1 and 11.2 RANI).

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

In principle yes, the law provides that the granting authority may require the concessionaire to expand the network on grounds of safety and frequency and quality of supply, if such expansion is consistent with the concession (*Base* XVIII DL 140/2006).

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Yes. See question 6.7 above.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

The transfer or assignment of a concession without the previous authorisation of the granting authority is void. For these purposes, the assignment of shares which results in a change of control is considered equivalent to the transfer of concession, and therefore also requires authorisation. On the same terms, the transfer of a local distribution licence is also conditional on the authorisation of the competent Minister (s. 27.1 DL 140/2006).

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Natural gas trading may be carried out under one of the following regimes: (*i*) free trading; and (*ii*) last resort trading.

Operating under the free trading regime is subject to registration with DGEG (ss. 33 and 34 of DL 140/2006). An operator under this regime has the right to trade natural gas through bilateral agreements with other agents or in organised markets, access necessary infrastructure, and freely agree on the sale of natural gas with its customers (s. 35.1 DL 140/2006). On the other hand, such operators are also bound to the regular provision of information to the regulator and to their customers, concerning *inter alia* consumption levels, prices and tariffs (s. 35.2 DL 140/2006).

On the other hand, the last resort trading regime is deemed to be a public service, whereby operators supply natural gas to economically vulnerable customers (s. 40.3 DL 140/2006) – both at the wholesale and retail levels (s. 40.1 DL 140/2006). These operators benefit from a tariff which aims to guarantee the economic and financial viability of the activity (s. 41.2 DL 140/2006).

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8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Legal entities which carry out natural gas trading have to be independent and autonomous from other legal entities which provide other services in the natural gas value chain (i.e. transportation, storage, etc.).

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

LNG storage and regasification terminals are operated by concessionaires (s. 18 DL 140/2006). The award of the concession follows a public tender or a tender restricted by a pre-qualification phase, and culminates with the signature of a concession agreement between the concessionaire and the granting authority.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

See question 9.1 above.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Access to the LNG Terminal is granted through an agreement entered into between the terminal operator and the interested party. The operator will charge a fee for the use of the relevant infrastructure under the terms of the RANI.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

As mentioned, third-party access to LNG facilities is formalised by an agreement to that effect. The general terms of such agreement have to be approved by ERSE, and are entered into for a maximum period of one year, between 00:00 on October 1st and 24:00 of September 30th of the following year. These agreements are automatically renewable for successive one-year periods (ss. 11.1 and 11.2 RANI).

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The National Oil System (*Sistema Petrolífero Nacional* – hereinafter "**SPN**") is made up of the following activities: (*i*) refining of crude oil and petroleum products; (*ii*) storage of crude oil and petroleum products; (*iii*) transport of crude oil and petroleum products; (*iv*) distribution of petroleum products; and (*v*) sale of crude oil and petroleum products (ss. 12.1 and 12.2 of DL 244/2015). The exercise of these activities falls under a regime of free competition, subject to the caveat that operators do provide a public service (s. 4.3 DL 244/2015) – meaning, in other words, operators have to comply with public interest principles such as safety, frequency and quality of supply, consumer protection and the promotion of energy efficiency.

The same entity can carry out more than one activity which composes the SPN (s. 11.2 DL 244/2015), and the exercise of any such activity is subject to certification by the ENMC (s. 12.1 DL 244/2015).

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

As mentioned, oil trading is one of the activities which integrates the SPN; as such, it is subject to certification. In particular, oil trading does not require any autonomous licence, despite the licensing of the facilities and the certification of the operator by the ENMC being required (s. 19.1 DL 244/2015). Traders may be retailers or wholesalers, and different rights and obligations apply to each type of agent (s. 20.1 DL 244/2015).

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The competent governmental authority in this regard is the Competition Authority (*Autoridade da Concorrência* – hereinafter "**AdC**"), although in the domains of oil and gas the AdC may be complemented by the powers and competences of ERSE and ENMC.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The Portuguese Competition Law establishes *inter alia* the following practices as anti-competitive: (*i*) fixing prices; (*ii*) limiting or controlling production, distribution, technical development or investment; (*iii*) dividing the market or supply sources; and (*iv*) applying different conditions to commercial partners supplying an equivalent good or service (s. 9 of the Competition Law approved by Law no. 19/2012 of 8 May 2012). The aforementioned statute also includes abuse of dominant position and abuse of economic dependence (ss. 11 and 12 Law no. 19/2012 – hereinafter "**Law no. 19/2012**").

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The AdC may investigate particular transactions or market practices if it suspects anti-competitive practices. Complaints may also be filed with the AdC regarding the same.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Company mergers are subject to a procedure of previous notification if:

- as a consequence of the merger, the national market share acquired, created or re-inforced, becomes equal to or surpasses 50% (s. 37.1(a) Law no. 19/2012);

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- the national market share acquired, created or re-inforced, corresponds to 30%–50%, as long as the individual annual turnover obtained in Portugal for at least two members of the merger is over EUR 5 million (s. 37.1(b) Law no. 19/2012); or
- the group of relevant companies obtained, in Portugal, a turnover of over EUR 100 million, as long as the individual annual turnover of at least two of the members was over EUR 5 million (s. 37.1(c) Law no. 19/2012).

For the purposes of the Competition Law, a merger is any operation where there is a long-lasting change of control on all or part of one or more companies (s. 36.1), be it via the merger of two previously independent companies or parts of companies, or the direct or indirect acquisition of control of at least one company. The incorporation of a common company qualifies as a merger for these purposes if the common company incorporated carries out activities as an economically autonomous entity (s. 36.2).

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

No further restrictions apply to foreign companies.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Besides EU laws and regulations applicable to the oil and natural gas sector, Portugal is also a signatory to the Energy Charter Treaty and a member of the International Energy Agency.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

DL 109/94 elects arbitration as the resolution mechanism for any disputes arising out of the interpretation of legal and contractual provisions between the State and the concessionaires. The seat of such arbitration is Lisbon, and Portuguese arbitration law will apply (s. 80 DL 109/94).

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

In 1994, Portugal acceded to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, subject to the reservation of reciprocity.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

No specific difficulties will apply in a suit brought against the State or a public authority.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

To our knowledge, there are no such judgments or awards.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

The upcoming developments in the oil and gas sector in Portugal will probably be motivated by the government's efforts to promote the Sines LNG Terminal, due to its geographic location, as a centrepiece in the supply of the European LNG market; which would, in principle, provide an alternative entry point for hydrocarbons into Europe, avoiding the politically more contentious routes through Algeria and Russia.

On this point, the Portuguese Ministry for the Sea and the United States Bureau of Energy Resources have signed an agreement for the promotion of LNG, in which both countries recognise the increased role of the Sines Terminal as the LNG hub of the Atlantic Ocean.

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Chapter 22

Romania

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Romania has the largest natural gas market in Central Europe and was the first country in the world to use natural gas for industrial purposes.

In 2016, Romania's natural gas reserves were estimated at 100 billion cubic metres (bcm) in BP's *Statistical Review of World Energy 2017*. According to the data provided by the National Agency for Mineral Resources (ANRM), at the current yearly depletion rate of 5 per cent, in conjunction with an 80 per cent replacement rate of natural gas reserves and considering the average annual production of natural gas in Romania (9.2 bcm), without new field development, Romania is deemed to have another 13 years' worth of conventional production.

According to the US Energy Information Administration (2013), Romania has 1,610 billion cubic metres of technically recoverable shale gas resources. The U.S. company Chevron Romania Holdings B.V. recently completed one shale gas exploration drill, but later decided to abandon the operations in Romania due to difficult market circumstances.

Detailed official information on gas reserves is classified.

Romania's natural gas production in 2016 was 9.2 bcm, down 6.5 per cent from the 9.8 bcm produced in 2015. Romania is the biggest producer of natural gas in Central and Eastern Europe (CEE). The main gas producers are Romgaz and OMV Petrom, which together covered approximately 94 per cent of domestic gas production in 2016.

According to the Romanian Energy Regulatory Authority (ANRE), in 2016, natural gas consumption amounted to 10.6 bcm, growing by 6.2 per cent compared to the previous year.

Romania has a unique position in the region through limited dependence on external sources of natural gas. Although import is considered a necessity due to the reduced flexibility of domestic gas production, combined with relatively large variations in seasonal consumption of natural gas, in 2017, natural gas imports grew by approximately 700 per cent compared to the previous year.

In terms of prospective new gas field developments, the Black Sea offshore is a promising area, especially in the deep-water sector, with production likely to commence in 2019.

The current physically available natural gas export capacity is limited to the point of interconnection with Hungary (Csanédpalota) and the point of interconnection with Moldova (Iasi-Ungheni). Although the Iasi (Romania)-Ungheni (Moldova) Interconnector was completed at the end of June 2014, exports were delayed due to technical and commercial reasons. The Szeged (Hungary)-Arad (Romania) Interconnector, commissioned in 2010, has operated only in the west-to-east sense at 1.7 bcm out of its 4.4 bcm/year capacity. As of 1 January 2014, small volumes of gas can be transported in reverse flow from Arad (RO) to Szeged (HU).

Romania's interconnection capacity with neighbouring States will improve once the Giurgiu-Ruse interconnection pipeline becomes fully operational. Although the interconnector was expected to be completed by the end of 2014, the gas transmission operators Bulgartransgas and Transgas have completed the construction of the interconnection pipeline Bulgaria-Romania only in November 2016. The interconnector Bulgaria-Romania has a total length of 25 km, of which 15.4 km on Bulgarian territory, 7.5 km on Romanian territory and a 2.1 km underwater pipeline pulled under the Danube. This pipeline project is part of the Bulgaria-Romania-Hungary-Austria interconnector (BRUA), which will connect natural gas networks in four countries, will provide connection to the Southern Corridor and will collect natural gas from the Romanian Black Sea continental shelf. The Romanian part of BRUA shall be partly financed as an EU Project of Common Interest (PCI).

In 2016, the natural gas TSO, Transgaz, offered for bid natural gas transport capacity on one of the three transit pipelines which used to be reserved by Gazprom for gas shipments to Bulgaria. The winners of such bid procedure were Bulgargaz EAD, Transenergo SA and WIIE Romania SRL.

Romania's natural gas interconnections with the transport systems of neighbouring countries have significantly improved in recent years. A major technical hurdle that Bucharest must deal with, in order to fulfil its reverse-flow obligations, is related to the lower pressure in the Romanian gas transport system. Exports will demand a sizeable compression capacity to be implemented next to the exit points. Recent developments indicate that the Romanian authorities are considering several solutions to mitigate this issue. In the context of the efforts made at European level, to strengthen regional energy security, during the Eastern Partnership Summit held in Riga on 22 May 2015, Romania, Bulgaria, Hungary and Slovakia signed an agreement to interconnect their natural gas transmission networks to allow mutual natural gas transit.

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Moreover, in April 2015, Transgaz concluded a memorandum of understanding with the natural gas carrier from Ukraine, Ukrtransgaz, aiming at identifying the technical solutions for reversing the flow of natural gas, to ensure the export of an estimated amount between one and two billion cubic metres of gas per year from Romania to Ukraine.

Romania has no LNG import or export facilities. The possibility of developing such facilities lies in the Azerbaijan-Georgia-Romania Interconnector (AGRI) project, which involves the construction of two terminals for liquefaction (on the Georgian coast of the Black Sea) and regasification (on the Romanian coast of the Black Sea). Although at a standstill for several years, the Romanian Government intends to revive the project. However, the chances of the AGRI project being implemented are low, at least for the near future.

The number of participants in the gas market in Romania has grown steadily as it has been liberalised, so that in 2016 it comprised: a National Transmission System Operator – Transgaz Medias; six producers (Romgaz, OMV Petrom, Amromco Energy, Raffles Energy, Foraj Sonde, Hunt Oil and Stratum Energy); six foreign suppliers that bring natural gas from foreign sources in Romania (Wintershall, Axpo – Switzerland; GDF Suez, Imex Oil, Mol Zrt si Wiee – Hungary); two storage operators (Romgaz and Depomureş); 40 distribution operators (the largest being Distrigaz Sud Retele and E.ON Gas Distributie); 39 suppliers operating in the regulated natural gas market; and 76 suppliers operating in the competitive natural gas market.

Gas transport activity is considered a service of national public interest and a strategic operation. At present, the transport system operator is the State-controlled company Transgaz, which operates the National Transportation System (NTS). Legislative amendments enforced in recent years allow for private undertakings to become gas transport system developers and operators, subject to obtaining an operation licence.

Underground storage capacity of natural gas has been constantly developed. Out of the seven storage facilities installed in depleted reservoirs, six are operated by Romgaz, while the Targu Mures facility is owned by GDF SUEZ (the majority shareholder) and Romgaz.

The gas distribution activity in Romania is of public general interest and is subject to concessions.

Imports of gas from Russia are made by private middleman companies, such as Wintershall or Imex Oil. Among the main natural gas traders on the domestic market, OMV Petrom Gas has the biggest market share followed by the State-owned company, Romgaz.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

According to BP's *Statistical Review of World Energy 2017*, the structure of the primary energy resources consumed in Romania, in 2016, was the following: crude oil – 29 per cent; usable natural gas – 29 per cent; coal – 16.5 per cent; hydroelectricity – 12.5 per cent; and renewable – 6 per cent.

Currently, the country has no installed LNG capacity.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

In 2016, Romania's natural gas consumption was 10.6 bcm, and Romania produced 9.2 bcm (according to BP's *Statistical Review of World Energy 2017*).

The required quantities of natural gas from other sources (other than domestic production) and those stored in the cycles of injection are covered by means of imports from Russia via nine importers. During 2016, the quantity of natural gas imported increased sevenfold to a total of 1.48 billion m^3.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

The first natural gas delivery to the Republic of Moldova took place in March 2015 through the Iasi-Ungheni interconnector. Currently, the pipeline provides 1 per cent of Moldova's total natural gas demand.

The development of the export capacity at the Hungary-Romania interconnection point, to a capacity of 1.75 bcm/year, at a pressure of 40 bar, is estimated to be completed in 2019. In the past (2013), minor quantities of virtual exports took place through back-haul procedures from Romania to Hungary.

With improving interconnectivity, moderate gas exports – about 1 bcm/year – will likely be possible by 2020. The flipside is that, thanks to reverse-flow capacity, by 2020 Romanian consumers will also be able to import natural gas from new regional sources:

- the Southern Gas Corridor (via the Greece-Bulgaria and the Bulgaria-Romania interconnections, which are works in progress);
- the Adria LNG terminal on Croatia's Krk island and the Croatia-Hungary and Hungary-Romania links; and
- the EU-supported North-South corridor, planned to connect the LNG terminals of Croatia and Poland.

Currently, the country has no installed LNG capacity.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Since 1990, Romania's oil sector has undergone several changes, including the privatisation of its largest oil and gas company, Petrom. This has not diminished the oil sector's importance to the Romanian economy.

Romania's oil reserves are limited, given that the discoveries of the past 30 years can be categorised as modest, except for some recent indications coming from the shallow waters of the Black Sea.

Romania's oil reserves were estimated by BP at 100 million tonnes in 2016. According to the data provided by the ANRM, at the current yearly depletion rate of 5 per cent, in conjunction with a 5 per cent replacement rate of crude oil and condensate reserves, and considering the average annual production of oil in Romania (4 million tonnes), without new field development, Romania is deemed to have another 23 years' worth of oil production.

Nevertheless, detailed official information on oil reserves is classified.

Although Romania's oil production is experiencing a natural decline, due to depletion of reservoirs, since 2012, the oil production was stabilised at around 4 million tonnes. Thus, Romania remains the fourth oil producing country in the European Union and the fifth in Europe, domestic oil production amounting to a quota of 2 per cent of production in Europe and 6 per cent in the EU. Romania imports about 60 per cent of its crude oil supply, most of it from Russia and the Caspian Basin. In 2016, oil imports amounted to 7.4 million tonnes of oil equivalent up from 7.150 million tonnes of oil equivalent.

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Romania has, theoretically, the largest installed capacity of refineries in Central and Eastern Europe. The country's main refineries have a high complexity index.

Regarding the refining capacity, out of the country's 11 workable refineries, only three are presently in operation: OMV Petrom's Petrobrazi, where the entire domestic oil production is processed; KazMunayGas's Petromidia; and Lukoil's Petrotel, totalling 9 million tonnes of oil per year. They have utilisation rates totalling more than 60 per cent. Romania refines its entire oil production and imports. It does not export crude oil, but only oil products.

The national oil transportation system (Oil SNT) is managed by Conpet, whose majority shareholder is the Ministry of Economy. Conpet has about 3,800 km of pipelines and a total transportation capacity of 27.5 million tonnes per year. The rate of utilisation has suffered a decline from 28.8 per cent in 2009 to 21.6 per cent in 2014, following Rompetrol's construction of its own marine terminal in the Black Sea.

The Romanian Oil SNT is a public asset of strategic importance and Conpet has a monopoly over it.

Oil Terminal S.A. Constanta owns one of Europe's largest oil terminals in CEE, with a capacity of 24 million tonnes/year.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Crude oil and petroleum products account for around 26 per cent of Romania's gross energy consumption.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

In 2015, Romania's oil consumption was 9.5 million tonnes, out of which Romania produced 3.8 million tonnes (BP 2017 report). The difference was covered by imports.

2.4 To what extent is your jurisdiction's oil production exported?

There are no crude oil exports from Romania. Crude oil is refined domestically and only oil products (especially gasoline) are exported.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The main Romanian legal act that regulates activities related to the upstream sector (oil and gas) is Law 238 of 7 June 2004, published in the Official Gazette of Romania No. 535 of 15 June 2004, as further amended (Petroleum Law) and Government Resolution 2075 of 24 November 2004, approving the implementation rules of the Petroleum Law. These reflect the implementation of Directive 94/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons. In the Petroleum Law, *petroleum* refers both to oil and natural gas.

The competent authority responsible in the oil sector is the ANRM (as defined under question 1.1 above), organised as a specialised body of the central public administration, with legal personality, subordinated to the Government.

The ANRM is mainly responsible for: (i) managing the petroleum resources of the State; (ii) concluding petroleum agreements in the name of the Romanian State; (iii) supervising and verifying petroleum production in order to compute the royalties due by the title holders of petroleum agreements; (iv) monitoring the implementation of the measures set to protect the areas affected by petroleum operations; and (v) regulating underground storage operations of hydrocarbons, petroleum terminals and the national pipeline system.

The main piece of legislation regulating the gas sector (production, transport, distribution and supply) is the Electricity and Natural Gas Law 123 of 10 July 2012.

According to the Romanian Constitution and secondary legislation, all natural gas reserves are exclusive property of the Romanian State and their development is granted to private investors by means of concessions, following public bid call procedures. Complementary to the responsibilities of the ANRM, there is a second regulatory authority, the Romanian Energy Regulatory Authority (ANRE), with the role of enforcing secondary legislation applicable in the natural gas sector (such as the issuance of licences and authorisations, including those required for the production of natural gas), drafting of technical requirements related to natural gas production and supply activities or the organisation, co-ordination and supervision of the natural gas market.

The construction of new upstream gas supply pipelines and gas transmission, storage and distribution systems, by Romanian or foreign legal entities, further require establishment permits issued by the ANRE.

The performance of natural gas supply activities (including biogas/bio methane, LNG, LPG, CNG/CNGV), and storage of natural gas, operation of the gas upstream supply pipelines (related to the production, transmission and distribution systems) and of the LNG terminals, as well as the management of the natural gas centralised markets, require licences issued by the ANRE.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Considering that oil and natural gas represent State-owned mineral resources (*in situ*), the rights related to the development of such resources are transferred to Romanian or foreign legal entities following public tendering procedures by means of establishing a concession right of the investor over the State-owned resource. The concession right in each exploration and/or exploitation block (perimeter) is granted based on a contract called a "petroleum agreement" (Rom.: "*acord petrolier*"). Such contract has standard provisions, being part of the tendering documentation, and is concluded between the ANRM, as a representative of the State, and the private legal entity or group of companies who have the required know-how, technical capabilities and financial means for performing such activities, and who are designated as successful bidders during the public tendering.

The object of the petroleum agreement includes both the right and obligation on behalf of the title holder to perform the exploration and/or exploitation and production activities within the area comprised in each block (perimeter). The investor can sell the production and has the obligation to pay to the State budget an annual production revenue (royalty).

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3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Depending on the rights to be granted to the investors, the following types of petroleum agreements may be concluded for the development of oil and natural gas resources: (i) petroleum agreements for exploration/development/production; (ii) petroleum agreements for development/production; and (iii) petroleum agreements for production.

The right to perform exploration and/or production operations is granted by the ANRM under the petroleum agreement. The commencement of petroleum operations must be approved in writing by the ANRM. The authorisation on the commencement of relevant operations is issued once the title holder proves that it holds additional permits, authorisations and endorsements required from several national and local authorities, such as the ANRE or the Environmental Agency.

The right to perform exploration operations only may be granted through a separate prospecting permit. This permit is issued by the ANRM for a three-year period, without extension, and is non-exclusive. It can be simultaneously granted to several applicants to conduct exploration operations in a defined petroleum block (perimeter).

The title holders of petroleum agreements also have the obligation to perform a minimum exploration programme, expressly provided for under the petroleum agreement.

About the terms of each type of petroleum agreement: these are mainly established by law and are negotiable only to a limited extent. Petroleum agreements for the concession of development and/or production of oil and natural gas reserves are concluded for a maximum period of thirty (30) years, with a potential extension of up to fifteen (15) years.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

According to the Romanian Constitution and the Petroleum Law, the State has the ownership right of all oil and natural gas reserves (*in situ*) located within Romania's territory. Therefore, the State's rights in this regard are a matter of law. There is no legal prohibition for the State to develop activities in the field of exploration and production of oil and natural gas. Such activities are currently performed by the national company owned by the State, Romgaz SA – in the natural gas sector, or through companies where the State is a shareholder, such as OMV Petrom SA – in the oil and gas sector.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The State has the right to collect royalties from oil and natural gas development. In case of oil production activities, the royalty level varies between 3.5 per cent and 13.5 per cent, calculated from the gross production extracted at the surface of each well. The level of royalty is therefore influenced by the production capacity of each oil reservoir. The same is applicable in respect of natural gas production activities. The maximum natural gas royalty is 13 per cent.

The State collects a 10 per cent royalty calculated in respect of the gross income obtained from oil transportation and transit activities (through the national oil transportation systems) and of petroleum operations (through oil terminals under the public property of the State), as well as a 3 per cent royalty calculated from the gross income obtained from natural gas underground storage activity.

Following the enactment of Law 127/2014 on the amendment and supplementation of the Electricity and Natural Gas Law and of the Petroleum Law (hereinafter *Law 127/2014*), an important amendment to the royalty system has been implemented as of October 2014. Thus, the gross income obtained from oil transportation activities (performed through transportation systems other than the Oil SNT), as well as the gross income obtained from petroleum operations performed through oil terminals (other than those under the public property of the State), is also subject to royalty payments. The rate is due to be approved by means of a Government resolution.

In addition to royalties, gas-producing companies owe the Romanian State a windfall tax of 60 per cent which applies, as of February 2013, to their extraordinary revenues resultant from gradual price deregulation. Initially, the tax should have been applicable until 31 December 2016, but has been prolonged until December 2017.

In the same regard, the VAT has been decreased from 20 per cent to 19 per cent at the beginning of 2017.

3.6 Are there any restrictions on the export of production?

The right to export the oil and natural gas production obtained by a title holder of a petroleum agreement is expressly provided by the Petroleum Law.

However, there are technical restrictions in this regard, considering that the existing interconnection capacities of Romania have basically only one way of interconnection, allowing, for now, mostly the import of natural gas.

It should be noted that the gas infrastructure interconnectivity of the country has recently undergone significant progress (please see the answer to question 1.1 above), so that Romania has the prospect of becoming a net natural gas exporter by 2020.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are no special legal provisions on currency exchange restrictions, or restrictions on the transfer of funds derived from the production of oil and natural gas.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

Irrespective of the type of natural resources (oil or gas), the holder of a petroleum agreement may transfer its rights and obligations pertaining to a petroleum agreement only with the prior written approval of the ANRM. Absent the prior written approval of the ANRM, any transfer of rights or interests shall be null and void.

The ANRM will grant its approval for the transfer of such rights, if the petroleum agreement holder has the required technical and financial capacity to perform petroleum operations in compliance with the terms set forth by the petroleum agreement.

As a general principle, the title holder is entitled to dispose freely of the entire production of natural gas and oil.

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3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Each participant to the public bid call for concluding a petroleum agreement must include in the participation offer a bank letter of good standing, indicating its solvency and global liquidity levels, gross profit margin and financial profitability.

The petroleum agreement further contains a chapter entirely concerning environmental protection and risk management. This chapter explicitly stipulates that petroleum operations are strictly confined to the areas designated by the ANRM and the competent authority for environmental protection.

In the same regard, the petroleum agreement provides for measures to reduce the environmental impact of oil and natural gas development and to repair the damage incurred.

Moreover, Law 165/2016 on the safety of offshore oil operations (implementing EU Safety of Offshore Oil and Gas Operations Directive 2013/30/EU), entered into force in July 2016, regulates the minimum requirements necessary to prevent major offshore accidents and limit their consequences. Therefore, when assessing the technical and financial capacity of a participant to the public bid call for concluding a petroleum agreement, evaluation criteria are set forth, such as the cost of degradation of maritime environment, financial guarantee for covering the liability for damage which may result from oil offshore operations, including the liability for potential economic damage.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

In accordance with the Romanian Civil Code, the right to develop natural gas reserves may be pledged for security, and under the Romanian accountancy norms, the rights to develop oil and natural gas may be booked as fixed assets under the heading "concessions, patents and other similar rights and assets".

The execution and enforcement of a pledge agreement on the right to develop oil and natural gas reserves would, however, require the prior approval of the ANRM.

Notwithstanding the above, at present, minimum stocks of crude oil and/or petroleum products maintained in accordance with mandatory legal provisions may not be used as collateral. The European Commission formally requested Romania to ensure the correct implementation and application of the Council Directive 2009/119/EC (Oil Stocks Directive), by eliminating, among others, the restriction of using minimum stocks of crude oil and/or petroleum products as collateral.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

The executed version of the petroleum agreement is to be endorsed by seven different Ministries and then approved by the Government. In addition, specific authorisations and licences must be obtained from the ANRM and the ANRE, and a series of several other approvals and authorisations to be issued either at national level and/or at county and/or local level are necessary in order to start the activities and related operations. For example, the establishment and operation of upstream supply pipelines related to natural gas production may be performed only after the ANRE issues the required permit and licence.

Apart from some standard endorsements required for performing activities in this industry, the type and necessity of approvals and authorisations may further depend on several aspects, such as the location of the perimeter (onshore or offshore), the specifics of the neighbourhood areas (such as a natural reservation or a protected area), or the technology to be used. The building permit, environmental approval and authorisations related to personnel or occupational health and safety are, of course, part of the generally required endorsements.

From an environmental point of view, for the exploration phase, the environment protection authority (EPA) decides, on a case-by-case basis, whether an environmental impact assessment (EIA) is required and if the activities are likely to have significant environmental effects.

Regarding the production phase, exploitation works can only begin after the environmental agreement has been obtained and providing the necessary conditions for the capture of petroleum, disposal of waste water and, if necessary, flaring of the associated gas have been fulfilled.

Thus, an EIA is mandatory for the extraction of petroleum and natural gas for commercial purposes where the amount extracted is a minimum of 500 tonnes per day in the case of petroleum and 500,000 cubic metres per day in the case of natural gas. Moreover, the EIA is required by law in the case of pipelines with a diameter of more than 80 cm and a length of more than 40 km for the transport of gas, oil and chemicals.

For other projects, the Environmental Protection Authority (ANPM) must decide on the basis of established thresholds/criteria, or on a case-by-case examination, whether an EIA is required.

In addition, a population health impact assessment is mandatory for any activity which is subject to the EIA.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

The Petroleum Law establishes the necessity of drafting, by the licence holder, an abandonment plan in respect of the physical structures used in the production of petroleum, consisting of complex technical, economic, social and environmental documentation, justifying the closing of the petroleum well and providing for the necessary actions to ensure the financing and effective fulfilment of the measures for cessation of activity.

The abandonment plan shall be endorsed by the ANRM. The production rights may be abandoned only if all the necessary measures to protect the reserves, land and environment are taken. The procedure for the abandonment of a petroleum well is provided in the standard technical instructions regarding the approval of the abandonment of petroleum wells, adopted by the ANRM.

The above-mentioned provisions are similar for both oil and natural gas developments.

Title holders are financially liable until the reparation of all environmental factors that were affected by the petroleum operations is completed, in accordance with the reclamation plan, as approved by the National Environmental Protection Authority (ANPM).

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3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/ requirements of the legislation?

Gas storage activity is regulated under the Electricity and Natural Gas Law. Together with gas transportation, distribution and transit activities, gas storage falls under the regulated segment of the natural gas market. The scope of performing gas storage activities is to ensure security of supply for end-customers, to harmonise the seasonal, daily and hourly fluctuations in consumption of available gas sources, and to ensure the permanent physical balance of the national transportation system.

In order to perform gas storage activities, any legal entity, domestic or foreign, has to be duly licensed by the ANRE. All technical installations used in gas storage activities have to be approved in advance by the ANRE and other relevant authorities. The gas storage activity is subject to a regulated tariff established by the ANRE. As a rule, any gas producer, supplier, transporter, eligible consumer or foreign entity that benefits from gas transit is entitled to use the gas storage facilities located in Romania. However, the gas storage operator is entitled to refuse access to the gas storage facility for a legitimate reason.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Cross-border sales or deliveries of natural gas are not limited in Romania. Such activities begun in March 2015, when the first natural gas delivery to the Republic of Moldova took place.

At present, Romania does not have any LNG facilities, but is planning one development in the city of Constanta on the Black Sea coast.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Romanian legislation does not provide for specific terms or rules applying in respect to cross-border sales of oil and oil products, other than the ones established at the EU level.

As a rule, the undertakings that want to perform cross-border sales of oil and oil products on EU territory shall obtain an Operator Registration and Identification number ("ORI"). An ORI is a unique number in the European Community, assigned by a Member State customs authority to operators, based on which the latter may perform cross-border sales in the Community territory. The ORI number cannot be assigned between different operators and shall be used for the identification of undertakings in their relations with the customs authorities.

According to Council Regulation 2964/95, any person or undertaking importing crude oil from third countries or receiving a crude oil delivery from another Member State shall be obliged to provide information to the Member State where it is established concerning the characteristics of the imports or deliveries. In Romania, the competent authority to collect such data is the Ministry of Economy. The competent authority will communicate to the European Commission, at regular intervals, the information so collected.

For the performance of the cross-border sale of oil and oil products to a non-EU territory, the undertaking shall have to obtain an export licence.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

The natural gas national transmission system ("Gas SNT") and the Oil SNT are the public property of the State.

The transport of oil through the Oil SNT is a service of national public interest and strategic importance, whereas the transport of natural gas is a service of national public interest.

Under Law 127/2014, any entity may own and operate, subject to unbundling requirements, a natural gas transmission system, other than the Gas SNT under the public property of the State. Law 127/2014 also introduced the concept of "petroleum transportation system for natural gas", to differ from the national transportation system (SNT) managed by majority State-owned Transgaz.

At this moment, the only entity holding a Gas SNT licence (concession) is Transgaz, a joint-stock company, where the Romanian State owns 58.5 per cent of its share capital.

In the oil sector, the national oil transportation infrastructure is operated exclusively by Conpet, a State-controlled joint-stock company, the only entity holding an Oil SNT licence.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

In order to develop the natural gas and oil national transportation pipelines and the associated infrastructure, such operators would require an urbanism certificate, the approvals of the Ministry of National Defence General Staff and the Romanian Intelligence Service, the environmental authorisation and a building permit, just to name a few of the most relevant approvals, in order to proceed with the performance of the infrastructure construction, rehabilitation or modernisation works.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

The right to use the land to construct oil transportation pipelines or associated infrastructure will be acquired by the following means:

- purchasing the land and, if applicable, the buildings located on such land, at the price agreed by the seller and buyer;
- swap of land, accompanied by the reconstruction of the buildings on the newly granted land, if any, at the expense of the holder benefitting from the released land, in compliance with the parties' agreement;

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- leasing the land for a determined period, based on lease agreements;
- concession of land from the State; and
- concluding a partnership agreement between the owner of the land and the title holder of the petroleum agreement.

As for the construction of natural gas transportation pipelines or associated infrastructure, the developer shall benefit from the following rights *in rem* over the lands and other assets in the public or private property of natural persons or legal entities, as well as over the activities conducted by natural persons or legal entities near such infrastructure:

- the right of use for the execution of works required for development of transportation pipelines or associated infrastructure;
- the right of use for ensuring normal operation of the infrastructure by conducting repair, maintenance works and necessary interventions;
- underground, aboveground or aerial right of way for the installation of grids, pipelines, lines or other equipment and for access to their location;
- the right to obtain the restraint or cessation of several activities that might endanger individuals and assets; and
- the right of access to public utilities.

A decision of the Romanian Supreme Court confirmed that, as of October 2011 (the entry into force of the new Civil Code), in exercising the right of use and the right of way mentioned above, the undertaking benefitting from the special rights must pay an allowance to the landlord, as well as an indemnity in case any damage to the property occurs during the performance of construction works. Prior to October 2011, the above rights over the lands (either in private or public property) were exercised free of charge.

Nevertheless, in case the infrastructural work for the development of the oil or natural gas pipelines is declared to be of public interest, the Government and county councils or the Bucharest Municipality and the local councils are entitled to expropriate the necessary land.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

The operator of the Oil SNT is obliged to ensure access to all applicants considering the available capacity of the system and may refuse to grant access in the following situations:

(i) if there are solid reasons of a technical, operational or safety nature which may affect the system's operational security;

(ii) if the available pipeline capacity is not enough for the requested routes; and/or

(ii) if the oil to be transported does not match the quality specifications.

Third-party access to gas transmission systems, both Gas SNT and private gas transmission systems, shall be made under the ANRE-regulated regime. The grounds for refusal to grant access to third parties mentioned at points (i)–(iii) above are also applicable to the gas transmission systems.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

At present, the Romanian oil transportation system is not integrated or interconnected with any oil transportation system belonging to a third country.

The Romanian natural gas transport system has interconnection points with neighbouring countries at Mediesul Aurit (Ukraine to Romania), Csanadpalota (Hungary to Romania), Isaccea (Ukraine to Romania) and Ungheni (Romania to Moldova).

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Third-party access to national oil transportation and associated infrastructure takes place based on a framework agreement. The agreement is concluded between the national transportation system operator and the third party (the shipper) for a determined period, considering a transportation schedule drafted on a yearly basis.

The shipper must provide the oil quantities at a quality level as provided in the annexes to the agreement. In case the oil does not meet the indicated quality, the national transportation system operator is entitled to refuse the shipment. The operator of the national oil transportation system is entitled to refuse access to the transportation system in case that: (i) there are technical, operational or safety considerations that may affect the operation of the oil national transportation system; (ii) the shipper has not fulfilled the financial obligations assumed with the national transportation system operator in relation with prior shipments; (iii) there is no available capacity in the national transportation system; or (iv) the available capacity is needed to meet certain obligations in relation with the performance of public services by the carrier, as provided by law.

The tariffs for the oil transportation services are regulated by law, and the invoices related to such are issued weekly by the national transportation system operator, based on the quantities effectively delivered.

In the gas sector, the distribution or transport system operator cannot deny the access of third parties to the pipeline.

In case the interconnection or the facility expansion is economically justified, the distribution or transport system operator is obliged to bear the costs for the connection. In the event that the development of the gas transmission network or pipelines is not economically justified for the distribution or transport system operator, the applicant may participate *pro rata* to the financing of the gas transmission network or pipelines. In this situation, the assets of the applicant shall be taken over by the distribution or transport system operator, whereas the applicant is entitled to recover the invested amount, upon commissioning of the gas transmission network or pipelines, from the subsequent beneficiaries connected to such network or pipelines.

The costs associated with the Gas SNT interconnection, capacity reservation and facility expansions are to be paid by the interested third party by means of a "connection fee", as such is to be established under the access approval.

However, the ANRE has the right to compel the licensed transport operator to finance the required works, if such works are economically justified, with a view to grant access to those requesting it, if the transport operator declines access due to insufficient capacity or lack of components of the network to which connection is intended.

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6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

The transport of oil and natural gas through the Oil and Gas SNTs is based on framework agreements and cannot be negotiated. The tariff is regulated by the ANRM and the ANRE respectively, on a yearly basis.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The gas transmission, storage and distribution services are subject to concessions by the Government to Romanian or foreign legal entities. The distribution of gas is a public service subject to concession for one or several delimited areas – administrative-territorial units. After the award of a concession, for the purposes of operation, the concessionaire must obtain the specific transmission, storage or distribution licence from the ANRE, as well as related permits and authorisations. The licensed operators must assure the continuity of their activity and the access of third parties to the transmission or distribution network, under regulated conditions.

The natural gas distribution operators have the following main obligations: (i) to operate, to maintain and to develop the distribution network under safe conditions, economic efficiency and protect the environment; (ii) to provide the eligible consumers the natural gas quantities as mentioned in the sale-purchase agreements concluded between the eligible consumers and the natural gas suppliers; and (iii) to use the distribution network under equal and non-discriminatory terms and to provide all required information to the other distribution network operators and the competent authority.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

For the operation of the distribution network, a licence for natural gas distribution is required. Such licence is to be issued by the ANRE. Further, additional permits and authorisations must be obtained in order to operate a distribution network, these being similar to the authorisations required to construct and operate natural gas transportation pipelines.

Among others, for the operation of a distribution network, an environmental authorisation is necessary, to be issued by the competent environmental protection authority. In addition, the use of water resources (underground and surface water) for the purpose of a distribution network is regulated under a particular authorisation (Water Management Authorisation) issued by the Romanian Water Authority.

7.3 How is access to the natural gas distribution network organised?

Access to the distribution network represents the right of a producer, supplier and/or end-user to connect to the network. The access conditions to the natural gas distribution network are regulated by the ANRE.

The Electricity and Natural Gas Law provides for the conditions for the distribution operators, aiming to avoid non-discriminatory practices. Natural gas distribution is a national public interest service.

Concessions for natural gas distribution are granted by the Ministry of Economy, with the endorsement of the ANRE, such being exclusive about the delimited areas for which it is granted.

Access to the distribution network of an applicant/user implies the following stages:

- reservation of facilities for an applicant/user; and
- connection to the distribution network.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

The ANRE may require a distributor to grant capacity or expand its system in order to accommodate new customers.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Natural gas distribution is part of the regulated sector of the market. Prices and tariffs are established by the ANRE.

In order to determine the tariffs due to the ANRE, the distribution operators must draft an annual programme of development regarding their natural gas distribution network, and shall request the regulatory authority to endorse the investment programme for each regulated period for which regulated tariffs and prices are established.

The endorsement by the ANRE of the investment programme shall be granted for the purpose of determining costs and corroborating such with the approved tariffs and prices.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

There are no specific legal limitations as regards the acquiring of an interest in a gas utility of private nature. However, the assets which are part of the distribution network may not be subject to a transfer, considering that the distribution network is of public interest.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Natural gas trading is regulated under the Electricity and Natural Gas Law and the secondary regulations issued by the ANRE.

The domestic natural gas market consists of:

- a competitive market, including natural gas trading between suppliers and between suppliers and eligible consumers. On the competitive market, prices are freely formed based on demand and offer, as a result of competition mechanisms; and
- a regulated market, including activities with a monopolistic nature and supply at regulated prices and based on framework agreements. In the regulated segment of the market, prices

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and tariffs are set forth by the ANRE based on its own methods drafted for such purpose.

Currently, Romania has implemented two natural gas trading platforms, one being managed by the Romanian Commodities Exchange and the other by the Electricity and Gas Market Operator, OPCOM.

In 2012, the EU Commission opened an infringement procedure against Romania concerning restrictions on the export of gas. The Commission considered that by obliging the producers in Romania to give priority to sales on the domestic market, Romania created unjustified barriers to exports of natural gas. In this context, the amendments brought in October 2014 to the Electricity and Natural Gas Law are being examined by the Commission on whether these measures fully transpose the Electricity and Gas Directives and it will decide on the pending infringement cases accordingly. Moreover, in 2016, the Commission, following a complaint by Hungary, also carried out dawn inspections at the offices of the main players in the oil and gas sector, Transgaz, Romgaz and OMV-Petrom, under suspicion of agreements aimed at blocking gas exports from Romania to EU members.

The Commission also referred Romania to the EU Court of Justice on grounds of lack of adoption of the national natural gas supply emergency plan.

The Electricity and Natural Gas Law was recently amended in October 2016, providing the obligation of the natural gas producers and suppliers in Romania, from 1 December 2016 until 31 December 2021, to conclude agreements on the centralised market in Romania in a transparent and non-discriminatory manner, for the sale/purchase of a minimum amount of natural gas, which cannot be less than a percentage share, which is regulated under Government Resolution No.778/2016, of the natural gas amount for which such producer or supplier concluded sale/purchase agreements as a seller or buyer during that period.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas may be traded as an "unbundled" product, either on the competitive market or on the centralised and regulated market.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

LNG facilities are governed by the Electricity and Natural Gas Law and the LNG Technical Code issued by the ANRE. A relevant department under the ANRE monitors compliance with the provisions regarding LNG.

The applicable legislation provides for the technical requirements in the basic activities regarding LNG storage, transport, distribution and use of the LNG infrastructure, as well as the methods to exercise monitoring and inspections.

Currently, Romania does not have any LNG facilities. The Romanian Government has been planning an ambitious project, called the Azerbaijan-Georgia-Romania Interconnector, also known as "AGRI". The aim of the project was to bring natural gas from Azerbaijan, through Georgia, over the Black Sea, to the Romanian shore, so that the gas would be further transported to Western Europe.

The construction of a future LNG terminal in Constanta (Eastern part of Romania) has been recently included in the LNG project masterplan – the Rhine-Main-Danube axis, developed by an international consortium consisting of 33 participants, within the "Trans-European Network for Transport Program".

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The following authorisations and permits issued by the ANRE are required to construct and operate LNG facilities: (i) authorisation to construct new objectives related to LNG storage activity; (ii) authorisation for LNG storage and trading activities; (iii) authorisation of natural persons operating the units related to LNG storage; and (iv) permission granted to entities to conduct LNG commercial storage and trading activities.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

For building new major natural gas infrastructures, such as LNG installations, an exemption from the provisions of the legislation related to the pricing methodologies may be granted for a fixed period, under the following conditions:

- the investment must reinforce competition in the natural gas supply sector and improve the safety of supply;
- the risk level related to the investment is to be achieved only provided that an exemption is granted;
- the infrastructure must be owned by a legal entity which is separated at least in terms of its legal form from the system operators in the systems of which the infrastructure is built;
- tariffs shall be charged for the beneficiaries of the infrastructure in question; and
- the exemption does not negatively impact competition, the effective operation of the natural gas domestic market or the effective operation of the regulated system to which the infrastructure is connected.

The exemption decision shall be issued by the ANRE and notified further to the European Commission which decides on the amendment or withdrawal of the exemption decision.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Starting in 2013, Romania has implemented a new Technical Code for regulating LNG activities. Under this Code, LNG terminal operators must ensure third-party access to terminals based on objective, transparent and non-discriminatory conditions and are entitled to collect the access tariff. Further regulations in this sector are expected to be issued by the ANRE.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The Romanian downstream oil sector is regulated in accordance with the provisions of Directive 2003/17/EC of the European Parliament and of the Council of 3 March 2003, amending Directive 98/70/EC relating to the quality of petrol and diesel fuels. This Directive has been transposed into the Romanian legislation by Government Resolution 928/2012 regarding the conditions for the introduction of oil and diesel fuels on the domestic market. In order to ensure the implementation of Government Resolution 928/2012, the

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Ministry of Economy issued Order 2458/2012 and Order 2459/2012, regulating the system for monitoring the quantity and quality of oil and diesel fuels through the distribution stations. To ensure that the entities operating the distribution stations observe the oil and diesel fuels quality requirements, special inspection bodies, duly authorised by the Ministry of Economy, are entitled to take fuel samples on a regular basis and report the findings in order to apply sanctions.

Moreover, to duly report the findings to the European Commission, the Ministry of Economy issued Order 662/2004 that transposes into national legislation the provisions of Decision 2002/159/EC of 18 February 2002 in a common format for the submission of summaries of national fuel quality data.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The possibility of performing oil trading activities is provided under the Petroleum Law. The Petroleum Law expressly provides that the title holder of a petroleum agreement is entitled to perform oil trading activities on the domestic market, including oil export. The main statutes related to oil trading activities are Government Emergency Ordinance 271/2000 regarding the legal regime of transportation, commercialisation and recovery of oil products and Ministry of Public Finance Order 1849/2016 regarding the procedure and conditions for registration of undertakings that sell energy products (including oil products).

In compliance with the provisions of the Emergency Ordinance 271/2000, the title holders of the petroleum agreements, the undertakings that import oil and oil products and the undertakings that process oil products are authorised to sell oil and oil products. However, according to Order 1849/2016, any undertaking that intends to trade oil or oil products must first obtain a trading certificate to be issued by the Directorate of Excise Duties and Customs Operations, part of the Ministry of Finance. Some of the most important conditions that must be observed by any undertaking interested in the wholesale or retail of oil and oil products are the following: (i) there are no outstanding debts to the State budget; (ii) the company was not declared fiscally inactive; (iii) the company holds proper storage facilities for the oil and oil products; and (iv) the premises where the specific activities will be performed must be equipped with video monitoring systems.

If all conditions are met, the Directorate of Excise Duties and Customs Operations will issue the trading certificate and the applicant will be registered in a special registry.

Trading of oil or oil products performed by an unauthorised undertaking may be considered a misdemeanour, which is subject to a fine, or under certain circumstances, an offence, subject to criminal law.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The Competition Council, an autonomous Government authority established in compliance with Law 21/1996 on competition (Competition Law), has authority in regulating competition aspects, as well as in investigating and sanctioning any anti-competitive practices.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

As a rule, the Competition Council will analyse any agreements, decisions of associations of undertakings or concentrated practices that have as their object or effect the prevention or distortion of competition on the Romanian market or on a significant part thereof. At the same time, any abuse of a dominant position by an undertaking (irrespective on how the dominant position has been obtained) will be sanctioned.

There are no pre-defined criteria to be observed by the Competition Council. In general, the regulator will analyse the object and/or effect of a conduct and, if such are deemed to affect competition, the regulator will intervene. Some hard-core restrictions, expressly provided by law (such as cartels, for example) will not require proofs attesting to their effects on the relevant market in order for an infringement to be found.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The pre-emptive role of the Competition Council is quite limited. In order to educate undertakings active on a relevant market, the regulator issues guidelines or instructions allowing such undertakings to better understand how the principles of competition law would apply to their domain.

At the same time, by controlling mergers, the Competition Council prevents companies combining their strength in entities with a dominant position, especially when there is a high probability of abuse of such position.

However, the regulator takes the most important actions to stop anti-competitive actions during or following investigations for alleged infringements of competition law.

During the course of an investigation, the Competition Council may impose any interim measures it considers appropriate if, following a *prima facie* assessment of the investigated practices, it comes to the conclusion that there is a risk of grave and irremediable damage to competition. Such measures may be imposed for a limited period but may be extended if the Competition Council considers them adequate and necessary.

If, following an investigation, an infringement is found, the regulator may (i) order the cessation of the identified anti-competitive practices, (ii) provide recommendations, (iii) impose special terms or other obligations to the parties, or (iv) apply fines.

Generally, any agreements or decisions that are found to be infringing Competition Law are null and void.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

As per the Petroleum Law, the title holder of a petroleum agreement may totally or partially assign to another entity the rights obtained and the obligations assumed by it subject to the prior written approval of the ANRM. The partial assignment shall refer to:

i) a share of the acquired rights and obligations undertaken under the petroleum agreement regarding the entire petroleum block;

ii) a share of the acquired rights and obligations undertaken by the petroleum agreement with regard to a petroleum area; and

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iii) all rights acquired and obligations undertaken by the petroleum agreement with regard to a petroleum area.

In case of a partial transfer as per points (ii) and (iii), the ANRM shall be entitled to impose delimitations of the petroleum areas located within a petroleum block. Any assignment concluded in the absence of the approval of the ANRM shall be null and void.

The distribution concession right can be withdrawn by the concession grantor in the event that the title holder: (i) fails to complete the volume of works within the due dates provided in the agreement; (ii) fails to observe the essential provisions defined as such by the parties in the agreement, which mandatorily include the provisions regarding the payment of royalties and environmental protection; and (iii) systematically breaches the validity conditions of the gas distribution licences or of the legislation related to the safe operation of objectives.

Upon termination of the concession agreement, the assets related to the public distribution service which are in the ownership of the concessionaire can be taken over either in full or in part by the concession provider or by another concessionaire, based on the approval of the former, in exchange for a compensation equal to the regulated amount left non-depreciated, established by the ANRE.

According to the Competition Law, any economic concentration in which at least two parties are involved, each having a turnover in Romania of minimum EUR 4 million and a cumulated turnover in excess of EUR 10 million, must be notified to the Competition Council for clearance. However, these thresholds may be amended by decision of the Competition Council, which is implemented by order of the President of the Competition Council, after consulting the Ministry of Economy, Trade and Tourism, and enters into force six months after its publication in the Official Gazette of Romania.

An economic concentration occurs when there is a change of control on a lasting basis resulting from:

(a) the merger of two or more previously independent undertakings; and

(b) the acquisition of direct or indirect control of the whole or parts of one or more other undertakings.

If the scenario described under (a) above raises no problems about its applicability, there may be some difficulties in determining if a change of control occurs in case parts of an undertaking are acquired. It is usually considered that, if an undertaking takes control of parts of another undertaking, such parts being able to be regarded as a whole and to generate turnover, then there is a change of control in the sense mentioned by the Competition Law. Consequently, a case-by-case appraisal is required in order to determine if acquiring development assets, transportation or associated infrastructure or distribution assets may fall under the restrictions provided by Competition Law. The Competition Council will analyse the notified concentration and determine its effects on the market. Usually, within 45 days as of the date of receipt of a complete notification, the Competition Council will issue a decision with respect to the notified transaction.

However, if serious doubts exist with respect to the compatibility of the transaction with free competition on the relevant market, the regulator may decide to open an investigation in order to thoroughly analyse the notified transaction. A decision must be issued by the regulator within a maximum of five months as of the date of receipt of a complete notification. Usually, the entire procedure takes around three to four months.

The Competition Council may issue a decision (i) clearing the transaction, (ii) conditionally approving the transaction, or (iii) not allowing the notified concentration, when it raises serious barriers to competition on the relevant market.

Any transaction which fulfils the criteria for being notified to the Competition Council cannot be implemented prior to obtaining the approval from the authority. Failure to observe this obligation could lead to the application of a fine ranging between 0.5 per cent and 10 per cent of the turnover for the previous financial year of the year when the sanction is applied.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There are no discriminatory requirements or limitations on acquisitions of interests in the natural gas sector by foreign companies. Foreign investors benefit from equal treatment with Romanian investors. Foreign legal entities acquiring interest in a petroleum agreement must establish and maintain a branch or subsidiary headquartered in Romania.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

Harmonisation of Romanian domestic law with European law was first considered for Romania's accession to the European Union.

The provisions of the Petroleum Law have been substantially aligned with Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorisations for prospecting activities, as well as for the exploration and production operations of hydrocarbons.

As concerns the natural gas sector, the Electricity and Natural Gas Law has been harmonised with European Directive 2009/73/CE of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.

Moreover, the regulatory policy in the sector is in accordance with Directive 2008/92/EC concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users, Regulation 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) 1775/2005, and Regulation 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC, to name only a few.

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13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

As a general principle, any dispute arising in relation to petroleum agreements, concerning the exploration, development and production of oil and natural gas resources, should be settled amicably between the parties within 30 days. In case a settlement may not be reached, then the parties are entitled to submit a claim with the Romanian courts of law. However, in case there is a foreign element involved in the dispute, the parties may choose to settle their dispute in front of an international court of arbitration.

Any disputes related to the transportation, processing or storage of natural gas, downstream oil infrastructure, development or distribution of natural gas or oil, are to be settled amicably. In case the parties do not reach an agreement, the disputes shall be settled either by Romanian or international arbitration courts, as agreed by the parties, or by the Romanian courts of law.

An amendment of the legislation related to dispute resolution in the energy sector provides, as an initial step in resolving the dispute, for the possibility of the licensed operators acting in the natural gas sector to defer disputes related to access to natural gas systems to the ANRE (such as the transmission and distribution networks, LNG terminals, storage facilities, etc.). The dispute will be resolved by a committee of experts appointed within the ANRE, whereby the decision of the ANRE is definitive and binding on the parties.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Romania ratified the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, in 1961, under Decree 186/1961 and ICSID in 1975, under Decree 62/1975.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

As a rule, no special difficulty occurs in litigating or seeking to enforce judgments or awards, against Government authorities or State organs. Such State authorities do not enjoy any immunity in this respect, except for their assets, which are in many cases in the State's public property. Therefore, such may not be subject to a forced execution procedure.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

There were several claims before domestic courts between foreign corporations and State bodies. The most significant claims were related to breaches of the Competition Law by some foreign companies and to the non-observance of the State's obligations assumed under privatisation agreements in the oil sector, as well as related to the privatisation procedures. Litigation including foreign corporations and government authorities was recorded by initiation of third party claimants on issues pertaining to permitting and environment protection.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

According to the Electricity and Natural Gas Law, the price liberalisation on the gas market started for industrial consumers on 1 December 2012, while for household consumers, the price liberalisation commenced on 1 July 2013. The regulated prices for industrial consumers were eliminated on 1 January 2015, while for household consumers, the liberalisation process should be finalised by 1 July 2021.

Industry associations have negotiated with the ANRM an extensive legislative amendment designed to facilitate access of oil and gas operators to onshore exploration and production blocks, as well as, in case of offshore operators, to the coastal area. The legislative amendments for the onshore operators are still pending promotion and approval by the Government/Parliament.

A ruling of the Supreme Court of Justice (dated July 2015) clarifies the legal nature of shale gas, indicating that the term is properly regulated under the Petroleum Law, being covered by the statutory definition of "natural gas". Moreover, the Supreme Court of Justice concluded that the legal capacity to grant leases/concessions for petroleum operations related to shale gas is a prerogative pertaining solely to the Government of Romania.

Until the end of 2017, a new bid round (the 11th bid round) for petroleum concessions was expected to be organised by the ANRM, whereby new petroleum blocks shall be offered for bid for exploration and production activities of oil and natural gas (both onshore and offshore).

Government priorities for transmission systems refer to the development of reverse flow interconnectors and the development of transmission systems for the shipment of offshore natural gas from the Black Sea to the Romanian coast.

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Serbia

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In 2016, final consumption of natural gas amounted to 1,675 Bcm [https://www.energy-community.org/implementation/IR2017.html, (EC 2017 Implementation Report)]. The biggest exploration areas (e.g. Banatski Dvor) are located in the Serbian Autonomous province of Vojvodina. The only natural gas producer is a public joint stock company "Naftna Industrija Srbije" a.d. Novi Sad (NIS), majority-owned by Russian company Gazprom Neft.

The key market players in Serbia are wholly state-owned company JP "Srbijagas" Novi Sad (Srbijagas), transportation system operator (TSO) and owner of the grid, and a vertically integrated joint stock company "Yugorosgaz" a.d. (Yugorosgaz) (in the ownership of Gazprom o.a.o. Moscow (Gazprom) (50%), Srbijagas (25%) and Centrex Europe Energy & Gas AG (25%)), licensed public supplier and distribution system operator (DSO).

Serbia imports the natural gas from Russia, via the long-term agreement between Serbia and the Russian Federation, pursuant to which Russian Gazprom is nominated as the exclusive natural gas supplier to Serbia. The aggregate import flows in 2016 amounted to 1,804 Bcm (EC 2017 Implementation Report).

The 'destination clause' identified by the European Commission in the inter-governmental agreement for gas supply between Serbia and Russia was recognised as limiting the natural gas supplies only to the Serbian market and infringing the antitrust rules considering the consequential isolation of the Bulgarian gas market, and was annulled by the end of 2017 by the Protocol between the parties. It is expected to enter into force following the ratification procedure in both countries.

The right to freely choose a supplier in the market is guaranteed to all customers as of 1 January 2015. The transportation grid is comprised of a high-pressure gas pipelines grid, which in turn comprises main gas and distribution pipelines, and the facilities located within them. The length of the said pipelines is *ca.* 2,400 km in total. Medium-pressure gas grids and low-pressure local distribution grids are operated by Yugorosgaz and 30 other local DSOs.

Srbijagas and Yugorosgaz are not yet functionally unbundled to the state of compliance (even) with the Second Energy Package. Srbijagas continues to act as TSO and as the supplier of natural gas in Serbia. Despite incorporating the subsidiary "Distribucijagas Srbija" d.o.o. (a DSO) in 2015, Srbijagas still acts as the DSO in practice. Likewise, legal and functional unbundling of transport activities of Srbijagas was not successfully implemented in practice.

NIS owns "Elemir" gas refinery, whose prevailing business activity is the preparation of domestic natural gas for transport and production of liquefied gas and oil. According to the Licence Register run by the Serbian Energy Agency (AERS), there are: 33 licensed public suppliers of natural gas, most of which also hold a licence for unregulated supply; 66 licensed suppliers of natural gas; and 31 licensed DSOs.

In the retail gas supply market, Srbijagas is the dominant market player, accounting for *ca.* 87% of the total natural gas sales in 2016.

The only underground storage of natural gas has been developed by the company "Banatski dvor" d.o.o. (Banatski Dvor) founded by Srbijagas and "Gazprom Germania" GmbH, which still continues to be the only licensed operator of underground storage of natural gas. Banataski Dvor operates on a surface area of 54 square metres at a depth of 1,000 metres to 1,200 metres. Pursuant to the AERS 2016 Report in 2016, the maximum daily injected quantity was 2.6m cubic metres, whereas the maximum daily withdrawn quantities were 4.95m cubic metres. The prices for access to the natural gas storage at Banatski Dvor are regulated under the Energy Act (EA) [*Zakon o energetici*, (Official Gazette of RS nos. 145/2014)].

Currently, no LNG facilities exist in Serbia. The authorities are aware that construction of such terminal would significantly decrease the Serbian dependency on import of gas from Russia and that it would substitute the anticipated quantities of the South Stream (major CEE gas pipeline project cancelled by the European Commission in 2014). Serbia has received the offer to be involved in the project "AGRI" (Azerbaijan-Georgia-Romania Interconnector) from Romania that would enable transportation of natural gas from Azerbaijan to Europe. The "AGRI" transportation system should have an annual capacity of 5 to 8 billion cubic metres, and it envisages a gas pipeline running from Azerbaijan to Georgia, where gas would be turned into LNG and then transported to Romanian terminals for further distribution to European countries, including Serbia. After the completion of the feasibility study, Serbian and Romanian authorities plan to seek EU financing.

At the end of 2016, the Serbian Government has adopted the Decree regulating the Spatial Plan of the special purpose area for the infrastructural corridor of the main gas pipeline Niš-Dimitrovgrad, with detailed regulation [*Uredba o utvrđivanju Prostornog plana područja posebne namene infrastrukturnog koridora magistralnog gasovoda*

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Niš-Dimitrovgrad, sa elementima detaljne regulacije (Official Gazette of RS no. 102/2016)]. With 109 km of length and 400 m of width, Niš-Dimitrovgrad gas pipeline is intended to provide additional gas quantities to Serbia from Bulgaria and connect the Serbian gas market with that of Bulgaria. Niš-Dimitrovgrad gas pipeline is part of the main pipeline extending to the capital of Bulgaria, Sofia. The estimated value of the project was *ca.* EUR 60 million, which the Serbian Government intended to procure through EU resources. Construction of the pipeline is still pending. The initial deadline for completion of the project was the end of 2018, but no official extensions were announced to date. The project is to be implemented in conjunction with the *TAP* and *TANAP* gas pipelines that secure gas supplies from Turkey and Azerbaijan instead of Gazprom's South Stream.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Total energy requirements for 2017 amount to 15,399 Mtoe, which is almost the same as that estimated for 2016 (15,348 Mtoe). The Serbian energy requirements in 2017 were satisfied 69% by domestic production and 31% by net imports.

According to the planned primary energy production established in the Serbian Energy Balance for 2017, the following sources of energy were consumed:

- coal – 70%;
- oil – 9%;
- natural gas – 4%;
- hydro – 7%;
- biomass – 10%; and
- geo-thermal, solar, wind, biogas and landfill and sewage gas – less than 1%.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

According to the EC 2017 Implementation Report, natural gas production has covered only 16% of the natural gas demand in 2016, which closely corresponds to the proportion predicted in the Serbian Energy Balance for 2016 (26% from domestic production and 74% from imports from Russia). As for 2017, the Serbian Energy Balance for 2017's predicted ratio is 19% from domestic production and 81% from imports. No official statistics are available to date.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Serbia does not export natural gas.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

The production of oil in Serbia is done on 63 oilfields with 666 drill holes. NIS is the only company in Serbia licensed for the exploration and production of oil. Refining is done at two major refineries operated by NIS: Pančevo and Novi Sad, having the aggregate annual refinement capacity of 7.3m tonnes of crude oil.

The transport of oil derivatives in Serbia is done by rail, river and road. The only company engaged in oil pipeline transportation is JP "Transnafta", a wholly state-owned entity, which operates on non-discriminatory principles under the regulated prices (for access to the network). Transnafta is engaged in oil transport by oil pipelines within entire territory of Serbia, whereas the product pipeline (*produktovod*) for transport of oil derivatives is still in design phase.

Currently, pipeline transport is only performed through oil pipeline in Sotine, at the border with Croatia, to Novi Sad and Pančevo, Serbia, where the two refineries are located at. The Sotine-Novi Sad section is 63.3 km long, whereas the Novi Sad-Pančevo section is 91 km long. This oil pipeline is part of the main Adriatic oil pipeline (*Jadranski naftovod*, "JANAF"), which operated since 1979.

By the end of 2016, AERS has issued: (i) 22 licences for storage of oil, oil derivatives and biofuels; (ii) 48 licences for wholesale of oil and oil derivatives, biofuels and compressed gas; (iii) 461 retail licences; and (iv) one transport licence.

The oil retail network in Serbia is done through the wide network of *ca.* 1,450 retail facilities, dominated by "NIS Petrol", "OMV Srbija" and "Lukoil".

Production of crude oil is done domestically and in Angola (at drill holes owned by NIS). Predicted supply of oil and oil derivatives in 2017 was expected to reach 24% from domestic production – 0.854m tonnes – and 76% from imports – 2.660m tonnes.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

As stated in question 1.2, oil accounts for 9% of Serbian energy requirements.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Only 24% of Serbian oil requirements are met through domestic oil production.

2.4 To what extent is your jurisdiction's oil production exported?

The planned export quantity of oil derivatives for 2017 was estimated at 0.8m tonnes (0.6m tonnes in 2016, which is *ca.* 50% higher than in 2015). The only market to which Serbia exports crude oil is the one of Bosnia and Herzegovina, while by-products are mostly exported to Kosovo and Metohia (petroleum and diesel), Bulgaria (euro diesel B-7), Romania and Hungary (aviation fuel).

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Exploration, extraction of natural gas, production, processing and refining of oil, as well as construction of mining facilities and mining works, are governed by EA and the new 2015 Mining and Geological Exploration Act (MGEA) [*Zakon o rudarstvu i geološkim istraživanjima*, (Official Gazette of RS no. 101/2015)]. MGEA's

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secondary legislation also governs specific areas of exploration and extraction of natural gas and oil. Oil and gas are considered mineral resources of strategic importance for Serbia under the MGEA, which, *inter alia*, ensures entitlement to expropriation.

The Serbian Ministry of Mining and Energy (Ministry) [*Ministarstvo rudarstva i energetike Republike Srbije*] is the competent authority for implementation of the EA and the MGEA – i.e. the competent authority for giving consent to the extraction of hydrocarbons and the construction of mining plants. In the event that a project is conducted on the territory of an autonomous province, provincial authorities will be competent for implementation of MGEA provisions. The MGEA stipulates that hydrocarbons are considered as natural resources owned by the Republic of Serbia and may be used under the conditions set out in the MGEA. Further, the Public Property Act [*Zakon o javnoj svojini*, (Official Gazette of RS nos. 72/2011, 88/2013 and 105/2014)] stipulates that natural resources, such as hydrocarbons, are public property.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The extraction of natural gas may only be conducted based on an extraction licence. The licence may be issued to a legal entity or entrepreneur holding an exploration licence. In order to acquire such licence, the applicant is required to prove the rights it holds over the pertaining land on which the extraction facilities are to be constructed (ownership, lease or easement). Under the MGEA, for oil and gas exploration and performance of mining works related thereto, a lease or easement right must be valid for up to 10 years. For exploitation of oil and natural gas, as mineral resources of strategic importance for the Republic of Serbia, a special act of the Government on determining the public interest shall be issued, in order to allow a five-year exploitation period for the applicant.

MGEA allows foreign legal entities to perform activities of geological exploration and exploitation, under the terms and conditions prescribed under MGEA, limitations as to use of public interest goods by foreigners and state defence and confidentiality restrictions. The new MGEA reduced the number of documents required for the issuance of various approvals to carry out geological exploration and exploitation of minerals, thus easing the process for private investors.

Further, the licence for exploration of oil and natural gas is given on the basis of a "public tender" procedure, initiated and conducted by the Ministry, in line with MGEA provisions. The licence for exploitation of mineral resources is issued by the Ministry, upon the duly submitted request of an applicant, i.e. by the competent authority of the autonomous province, if exploitation is to be conducted on its territory. On the other hand, the Public-Private Partnerships and Concessions Act (PPP Act) [*Zakon o javno privatnom partnerstvu i koncesijama*, (Official Gazette of RS no. 88/2011, 15/2016 and 104/2016)] specifically recognises exploration and exploitation of mineral resources and other geological resources as general interest activities, that may only be performed subject to concession arrangement regulated thereunder. The beneficiary of the results from previously implemented geological exploration may in principle acquire consent for exploitation and/or exploitation field based on confirmation on such exploration results.

Further, the PPP Act excludes the application of any other procedure for granting the right to perform these activities regulated under different legal acts, by stating that its provisions shall apply to the procedure on granting the right to perform them, whereas other legal acts may govern other significant matters pertaining to performance of such activities. Considering that the two acts (the MGEA and the PPP Act) contain conflicting provisions as to the procedure that needs to be applied and that there is no settled practice or authorities on this matter, it cannot be determined with full certainty which procedure would be applicable. The PPP Act seems to prevail over MGEA as it explicitly excludes application of any other act in terms of the applicable procedure.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

As stated in question 3.2 above, the exploitation licence can only be issued to a legal entity holding the exploration licence, obtained through the competitive procedure. The decree regulating the public tender for exploration of mineral resources has not been enacted. Under the PPP Act, a public tender procedure for concession is initiated upon the proposal of either the authority or the investor. Given that the said activities are considered public interest activities, the concession forms an integral part of the relevant licences for their performance. The concession agreement can be concluded for at least five years or a maximum period of 50 years, depending on the potential effects on the competition and the reasonable period for the amortisation of a private partner's investment and return of the invested capital. The exploration licence is issued for an initial period of three years, and it can be extended for two additional periods. Under the MGEA, these extension periods are for an additional three and then two years.

With regards to the terms of the exploitation licence, the MGEA only sets the term of two years for completion of the preparation works, whereas the term of the exploitation, i.e. use of the mineral resources, will be determined pursuant to production dynamics determined in the feasibility study and quantities of the relevant mineral resources' stocks. The exploitation also requires prior obtainment of the approvals for mining works and, ultimately, a use permit for the mining plant. Exploration, mining works, construction and the use of mining plants and other facilities are licensed by the Ministry and the provincial authority, depending on the location of the exploitation area.

In principle, the investor bears the risk related to the commercial use (exploitation) of the mineral resource. However, the distribution of risk between the public and private partner may be further regulated under the concession/public agreement.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

NIS is the only company in Serbia licensed for exploration and exploitation of oil and natural gas. The state holds 29.87% of the stake in NIS, 56.15% is held by Gazprom, and minority shareholders hold 13.98% in the stake thereof. For further state ownership and interests with regards to the oil and natural gas grids, please see question 6.1.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The investor is required to pay the following fees when engaged in mineral resources development:

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(i) exploration fee – the new MGEA sets the fee in the amount of *ca.* EUR 80 per square km of approved exploration area;

(ii) exploitation fee –for oil and gas exploitation, the exploitation fee amounts to 7% of the revenue achieved from their sale and use; and

(iii) concession fee – proposed by the investor when submitting the bid and determined in the concession agreement on the basis of the type of the mineral resource, type of activity, term of the concession agreement, commercial risk and expected revenue, fit-out and the surface of the exploitation area (quantity of the mineral resource), including the exploitation fee payable by the investor.

Notably, the ore rent, i.e. the exploitation fee payable by NIS, amounts to 3% of the revenue achieved from the sale and use of the oil and gas, pursuant to the agreement between Serbia and the Russian Federation.

3.6 Are there any restrictions on the export of production?

The EA and MGEA do not provide for any specific restrictions to the export of mineral resources (oil and natural gas). However, pursuant to the EA, potential restrictions may be imposed on export of mineral resources in case of crises and a general lack of mineral resources for meeting domestic requirements.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Pursuant to the Serbian Foreign Exchange Act (FX Act) [*Zakon o deviznom poslovanju*, (Official Gazette of RS nos. 62/2006, 31/2011, 119/2012 and 139/2014)], as of 1 October 2015, foreign payment transactions may be executed in both foreign and local (RSD) currency, through the banks.

Additionally, the FX Act states that the import and export of goods, agreed either in foreign or local (RSD) currency, can be considered a commercial credit and loan arrangement, if (i) the payment was not settled for more than one year, as of the moment of the completed import or export, and (ii) the goods were not imported/exported, i.e. imported for more than one year as of the day the payment in foreign or local (RSD) currency was settled. The commercial credit and loan arrangement must be notified to the National Bank of Serbia, as well as any change made in relation to such agreement. However, in practice, no transfers can be achieved without the official stamp of the National Bank of Serbia confirming that it has been notified. Cross-border loans cannot be repaid before the expiration of one year from the drawdown date, pursuant to a separate decision of the National Bank of Serbia.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

There are no specific restrictions on transferring oil and natural gas development rights and interests. The transfer of the licences for exploration and exploitation is permitted upon completion of certain typical requirements set under Art. 9 MGEA and the requirements to be prescribed under secondary legislation which was not adopted to date.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

In its proposal for granting a concession, a public partner may request a performance guarantee or other type of security from the investor under the concession agreement. Besides this, the public partner is obliged under the PPP Act to acquire from the selected partner a guarantee for payment of the concession fee. The amounts of these guarantees are determined on a case-by-case basis, considering the terms of the concession agreement. A standard seriousness-of-the-bid guarantee in the maximum amount of 5% of the total estimated value of the concession shall also be provided by the investor within the competitive procedure.

Pursuant to Art. 103 MGEA, an interested party applying for approval for the construction of mining facilities and/or for conducting the mining works is obliged to submit a bill of exchange (promissory note) or proof of bank guarantee or corporate guarantee for conducting the activities of remediation and reclamation of degraded land due to the exploitation in favour of the Republic of Serbia. Either of the said securities shall be issued in the amount of 30% of the total value of the project determined under the main mining project and shall be valid for the period of three years. Every subsequent security must be valid for two years and issued in the amount of 30% of the remaining value of the works. Final security must be valid for an additional 60 days as of the estimated date for completion of the works.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The PPP Act envisages that, with the previous consent of a public partner, security (in the form of a mortgage, pledge or otherwise) may be set up in order to secure the financing of the project. It further depends on the specific right whether it is eligible for encumbering.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Apart from the principle licences determined under the MGEA, the exploration and extraction of natural gas may also trigger other approvals and/or licences, mainly in construction and spatial planning, environmental protection, occupational health and safety, water management and waste management. The competent authority for issuing required approvals in the construction and spatial planning field, as well as in the field of environmental protection, is either the relevant Ministry or the local or provincial authorities, depending on the capacity and the location of the contemplated project.

For example, the construction and spatial planning approvals and permits are issued by the authority competent for the exploration/extraction area at hand (i.e. Ministry of Construction, Traffic and Infrastructure, local municipality or the autonomous province). Also, the competent authority depends on the type and the size of the project. Pursuant to the Spatial Planning and Construction Act (SPC Act) [*Zakon o planiranju i izgradnji*, (Official Gazette of RS nos. 72/2009, 81/2009, 64/2010, 24/2011, 121/2012, 42/2013, 50/2013, 54/2013, 98/2013, 132/2014 and 145/2014)], the Ministry of Construction, Traffic and Infrastructure is, *inter alia*, competent for issuing the construction permit for: (i) plants for the processing of fuel (oil) and gas (*rac*) that are constructed outside of the exploitation area; and (ii) gas pipelines with a normal working pressure of over 16 bars, if it passes through territories of two or more municipalities. An autonomous province shall issue a construction permit for the same

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plants if they are to be constructed completely on its territory. Lastly, the local municipality is competent for issuing the construction permits for all other plants/infrastructure that are not within the competencies of the above authorities, as specifically listed under Art. 133 of the SPC Act (e.g. residential buildings).

With regard to the environmental protection approvals, natural gas and oil extraction are considered activities subject to the environmental impact assessment study (EIA), pursuant to the Decree on the determination of the list of projects for which an EIA is required, and the list of projects for which an EIA may be requested [*Uredba o utvrđivanju Liste projekata za koje je obavezna procena uticaja i Liste projekata za koje se može zahtevati procena uticaja na životnu sredinu*, (Official Gazette of RS no. 114/2008)]. Additionally, pursuant to the Protocol on the strategic environmental impact assessment [*Zakon o potvrđivanju Protokola o strateškoj proceni uticaja na životnu sredinu uz Konvenciju o proceni uticaja na životnu sredinu u prekograničnom kontekstu*, (Official Gazette of the RS no. 1/2010)], a strategic environmental impact assessment study (SEA) may be requested for major mining, on-site extraction and processing of metal ores or coal and for surface industrial plants for the extraction of coal, petroleum, natural gas and ores, as well as of bituminous shale. EIA and SEA approvals must be issued before obtaining the construction permits. Finally, gas and mineral oil refineries are subject to the IPPC – Integrated Pollution Prevention and Control – permit [*Zakon o integrisanom sprečavanju i kontroli zagađivanja životne sredine* (Official Gazette of RS nos. 135/2004 and 25/2015)]. Potentially, Seveso II approval for prevention and control of the major accidents resulting from handling of dangerous and combustible substances (such as oil and gas) may have to be obtained. The competent authority for EIA/SEA approvals, an IPPC permit, as well as for Seveso II approval, is either the Ministry of Agriculture and Environmental Protection or the municipal authority or provincial authority competent for environmental protection, i.e. the same authority that was determined as competent under the SPC Act (as mentioned above).

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Pursuant to the MGEA, the exploitation area must be rehabilitated and reclaimed after the works on exploitation have been completed, at the latest after one year of such completion. This must be done in accordance with the reclamation plan and obligatory measures for the exploitation area's recovery and protection of the environment, water, land and public health and safety, as determined within the process.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The storage of natural gas is regulated under the EA. A natural gas storage system operator (SSO) is obliged to comply with the principles of objectivity, transparency and non-discrimination, with regard to access to the storage system, under regulated prices. An SSO must operate under the terms of the storage licence issued, pursuant to the EA. The SSO may reject third-party access to the system in certain justified cases such as a lack of system capacity (please see question 6.6).

Further, in order to access the system, the third party is obliged to:

- register with the SSO in order to participate in the allocation of the gas capacity; and
- submit a request for access to the system, in which it defines whether it is applying for an entry or exit point, the intended duration of the transport and the relevant type of capacity (i.e. permanent or temporary).

After the SSO allocates gas capacities based on the request of the third party (and minimum gas quantity expected), it notifies the third party thereof. Such notification is considered as the acceptance of the third party's request/offer.

After the third party receives a signed copy of the agreement by the SSO and has settled the advance payment (or provides a bank guarantee as a security for fulfilment of its payment obligations undertaken by the agreement), the SSO and the third party officially become parties to the access agreement.

As stated above, currently there is only one licensed SSO – the underground gas storage "Banatski Dvor". However, the relevant storage code has not yet been enacted. Therefore, *inter alia*, specific conditions and procedure for access to the storage grid, tariffs in line with methodology adopted by AERS, as well as the allocation of storage capacities, are not currently regulated.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Cross-border sales or deliveries of natural gas are accomplished by the bilateral agreement between the supplier and producer. There are no specific restrictions or rules pertaining to the cross-border sales or deliveries of natural gas, except in case of crisis (as described under question 3.6 above) and foreign exchange notification requirements, if applicable (as described under question 3.7 above).

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Cross-border sales or deliveries of oil are accomplished by a bilateral agreement between the supplier and producer.

Additionally, the Serbian Government adopted the Decree on marking of oil derivatives [*Uredba o obeležavanju (markiranju) derivata nafte*, (Official Gazette of RS nos. 51/2015 and 5/2017)] (Marking Decree), which has obliged all energy companies engaged in the production and trade of oil and oil derivatives to comply with the specific marking regime. The marking system requires that all oils imported to or traded within the Serbian market are marked in accordance with the Marking Decree and guideline rendered for its implementation (Guideline) by the exclusive provider of marking service – "SGS Beograd" d.o.o.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

In principle, the applicable regulatory requirements are stipulated in

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the EA, MGEA, the Act on the Pipeline Transportation of Gaseous and Liquid Hydrocarbons and Distribution of Gaseous Hydrocarbons [*Zakon o cevovodnom transportu gasovitih i tečnih ugljovodnika i distribuciji gasovitih ugljovodonika*, (Official Gazette of RS no. 104/2009)] (Pipelines Transportation Act), and other relevant gas and oil-related regulations.

Pursuant to the EA, oil and oil derivatives pipeline grids must be in public ownership and in the ownership of the transport operator established by the state for performance of transport activities. The natural gas pipelines may also be in private ownership. However, the EA failed to regulate requirements and restrictions regarding private ownership of the natural gas grid. The basic principle nevertheless remains that the grid or parts of the grids that are constructed by the private entity acting as a system operator, or acquired by it in a legal transaction, shall remain in its possession. The storage facilities are owned by the only licensed SSO – Banatski Dvor.

Srbijagas and Yugorosgaz operate pursuant to the rules set under the EA and their grid codes, approved by the AERS (Codes). The wholesale price of gas sold to the public supplier was regulated until September 2013, and thereon, the gas price is set according to the cost-reflective formula set in the tendering procedure whereby Srbijagas was appointed as the supplier of public suppliers. Public suppliers' prices are previously approved by AERS. The Codes regulate third-party access to the grid, injection into the gas grid and upstream pipelines, allocation of capacities, balancing, congestion management and other terms of the transmission services. TSOs must operate transparently and they must ensure third-party access on non-discriminatory grounds. Third-party access may only be rejected in certain cases, such as lack of capacity (please see question 6.6). The Codes also provide for a model access agreement to the transportation grid. However, the Codes do not allow for capacity rights transfer on a monthly and daily basis, only annually. The minimum assignable quantity is 2,000 cubic metres.

Pursuant to EA, AERS has also approved the oil transmission grid code rendered by Transnafta (Transnafta's Code). Transnafta's Code regulates the technical requirements for operation of the system, rules on the use of the system, transport models measuring terms, third-party access agreement, etc. Third-party access may only be rejected in number of instances such as the lack of capacity and inappropriate quality of the fuel (please see question 6.6). Transnafta's Code regulates the terms of the access agreement, which must specify, *inter alia*, the quality and the quantity of the fuel, term, payment dynamics, contractual penalties, etc.

As of 1 January 2015, the wholesalers are obliged to submit the reports on storage and transport of the oil, along with the delivery of the oil and oil derivatives.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

According to the SPC Act, a location permit and a building permit must be acquired for construction of, *inter alia*: (i) oil pipelines; (ii) gas pipelines; and (iii) product pipelines (*produktovod*). Pursuant to the Pipelines Transportation Act, the company licensed for transport, i.e. distribution through pipelines, must implement the measures for occupational health and safety, environmental protection, fire and explosions in accordance with separate legal and technical acts (please see question 3.11). The use/occupation permit may be acquired upon obtaining of the said environmental permits, as well as upon determining the fulfilment of the conditions set under the construction permit.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

According to the EA, the energy companies are entitled to use (lease, easement, etc.) the land owned by third parties for the purposes of construction, reconstruction or maintenance of energy facilities. Private land may also be expropriated provided that the Government has established the public interest in such a project and mineral resource (facilities in the area of energy infrastructure are considered objects of the public interest in general under the expropriation regulations, whereas the SPC Act considers pipelines as the facilities for public purposes).

In principle, the construction of the new pipeline infrastructure must be determined in the spatial plan of the special purposes area, and the detailed plan of the regulation of the project area. Additionally, pursuant to the MGEA, oil and gas pipeline construction may be subject to the prior approval of the Ministry, in case that the pipelines are designated to pass through the exploitation areas.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Third-party access to the transportation system is regulated by the EA and it secures access on a non-discriminatory basis. As stated in the answer to question 6.1 above, TSOs have mandatorily provided a model connection agreement within their Codes.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The TSO is obliged to cooperate with the other system operators and to provide support and all necessary information to the independent system operator. In its 10-year plan for the transportation system's development, the TSO must define and achieve its aims towards the procurement of the new interconnections with the neighbouring countries.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

As stated above, the TSO must enable third-party non-discriminatory access to the grid. The Codes and EA provide the instances in which the TSO may reject third-party access to the system in certain justified cases, such as: (i) a lack of system capacity; (ii) if such access would prevent the successful execution of the obligations for the security of supply; and (iii) in case of serious economic and financial hurdles incurred due to the "take or pay" obligations. The TSO is obliged to offer all available quantities up to a level which does not jeopardise the operation of the system. Although obliged by the EA, the Codes do not provide the obligatory offering of the unused capacities on the primary

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market at least on a day-ahead and interruptible capacity basis. The Codes and EA do not regulate the mandatory expansion of the system and capacities in case it is required by a third party seeking access.

The third-party access to the oil transmission grid, operated by Transnafta, is subject to the same principles of transparency and non-discrimination. Besides a lack of capacity, Transnafta may reject the third-party access due to the following reasons: (i) operational disturbances or if the system is overloaded; (ii) endangered security of the system; (iii) inappropriate quality of the oil and oil derivatives of the third party seeking access; and (iv) other reasons determined in Transnafta's Code (the code does not provide any specific grounds for rejection, and it is based on the non-discriminatory principle as well).

Due to the failure of SSO Banatski Dvor to adopt its storage code, third-party access is currently unregulated, which is against the EA. Despite of this, Banatski Dvor would have to uphold the basic principles of third-party access to the grid prescribed by the EA (e.g. principle of non-discrimination).

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Under Serbian law, natural gas transportation and the pipeline transportation of oil are public interest activities. The access tariff, i.e. entry-exit tariff, is determined by the TSO, based on the methodology rendered by AERS. The same applies for access to the oil transportation system, i.e. the final tariff is established by the TSO Transnafta in accordance with the AERS' methodology.

Other terms may be regulated by the access agreement between the relevant TSO and the party seeking the connection, provided that they comply with the principles under the codes (i.e. the Codes and the Transnafta's Code), EA or other applicable decisions of AERS.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Gas transmission and distribution are regulated energy activities and are considered as the public interest activities. Srbijagas has been partially unbundled in June 2015, as analysed in question 1.1. According to the licence registry of AERS, currently there are 31 companies licensed as DSOs. Pursuant to the last available information published by AERS in its Annual Progress Report for 2016 [https://www.aers.rs/Files/Izvestaji/Godisnji/Izvestaj%20Agencije%202016.pdf], the licensed DSOs are not subject to the unbundling requirements and they can be also engaged in supply activities, either on the regulated or market terms, given that they have less than 100,000 customers.

Transmission and distribution networks are subject to regulated third-party access (please see questions 6.1 and 6.6). The EA allows for the private ownership of the distribution and transmission networks, but it fails to regulate it specifically enough. The EA has established ownership of Srbijagas over the existing distribution and transportation networks in the market.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Pursuant to the EA, distribution networks may in principle be either in the public ownership, in the ownership of a DSO incorporated by the state, a company which is the subsidiary of a state-owned company, or in private ownership. As stated, Srbijagas is the owner of the distribution and transportation network that used to be in state ownership before the adoption of the EA in December 2014, and such ownership right cannot be alienated. Distribution of natural gas and operation of distribution networks is considered a general interest activity under the EA. A distribution network may thus be operated through a concession agreement granted pursuant to the PPP Act.

Transport system operators, i.e. DSOs, may acquire ownership over the transport network, i.e. the distribution network may acquire ownership over the facilities of the gas network that it has constructed with its own funds, or acquired with a business transaction, incorporation or capital increase.

7.3 How is access to the natural gas distribution network organised?

As is the case with the third-party access to the transportation and storage networks, access to the distribution network is secured by the EA on the basis of non-discrimination, as further regulated by the relevant operators' codes (please see questions 3.13 and 6.6).

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Access to the distribution system may be rejected on the grounds specified under the EA, such as a lack of capacity (please see question 6.6). Rejection on any other grounds may be disputed, upon which, presumably, AERS may order the DSO to grant capacities, provided that all requirements are satisfied. The EA does not regulate instances of expansion of the distributor's capacities in order to accommodate new customers.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Yes, the fees for access to the distribution system are regulated under the EA. Pursuant to the methodology adopted by AERS, the prices are determined by the DSOs and finally approved by AERS.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Pursuant to the EA, the distribution of natural gas may be performed by a private entity. However, the EA has established the ownership right of Srbijagas over the existing distribution and the transportation networks.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Serbia has implemented the entry-exit tariff model as of 1 January 2015. Currently, there is no commodity exchange or any gas hubs.

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8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

We are not aware of any restrictions to the types of commodities that can be traded with.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

Currently, no LNG facilities exist in Serbia. With regards to the planned construction of LNG facilities, please refer to question 1.1.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The LNG facilities' construction would be subject to a standard construction procedure set out under the SPC Act – obtainment of the location conditions, building permit and use permit. Additionally, certain LNG-related facilities (e.g. liquefaction and regasification plants) may be subject to the special environmental protection licences (EIA, SEA, IPPC permit and potentially a Seveso II approval).

9.3 Is there any regulation of the price or terms of service in the LNG sector?

Under the current legal framework, there are no defined price or terms of services in the LNG sector.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Third-party access related to LNG facilities is not regulated under the current legal framework.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream oil sector falls within the competencies of the Ministry, although there is no specific legal framework for oil trading at the downstream level. Oil trading is carried out pursuant to the market terms. The major oil market player is NIS, who also owns and operates the two biggest oil refineries in Serbia.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Oil trading is not a regulated energy activity under the EA, nor is it a public interest activity that is subject to a concession procedure under the PPP Act. Other than prices for access to the pipeline and product pipeline transport networks, oil prices, i.e. oil trading prices, are not regulated. Therefore, oil trading is performed on a contractual basis. The Directorate for Energy Reserves, as an administrative body under the Ministry, has been partially established in 2015. Pursuant to the Marking Decree, all oils and oils' derivatives produced within or imported to Serbia must be marked, in accordance to the procedure and requirements set thereof and in the Guideline, before being placed on the market.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

On the administrative level, AERS is the competent authority for monitoring and control of all energy activities. However, the competencies of the Commission for Protection of Competition (CC) remain unaffected with regards to the antitrust practices in the market.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

The regulator must take into consideration the Serbian Act on Protection of Competition [*Zakon o zaštiti konkurencije*, (Official Gazette of RS, nos. 51/2009 and 95/2013)] and the EA, as well as other applicable energy-related regulations.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

CC can initiate the investigation upon receipt of a complaint or *ex officio*. It is entitled to receive any information and documents required for investigation, from market players, state authorities and organisations, who are obliged to cooperate.

Upon completion of the proceedings, the CC may order behavioural or structural measures, conditionally approve an investigated agreement or practice, preclude it or prohibit the abuse of a dominant power position. CC may impose a fine in the amount of 10% of the total annual turnover of the relevant parties achieved within the territory of Serbia in the preceding year.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

The Serbian merger control regime regulates and monitors the concentration in the form of merger of the independent undertakings, acquisition of control and formation of a full-functioning joint venture.

A transaction has to be notified if either of the following thresholds is met:

(i) the aggregate worldwide turnover of all the undertakings concerned in the year preceding the concentration is at least EUR 100m, provided that at least one of the undertakings concerned achieved a turnover in Serbia of at least EUR 10m; or

(ii) the aggregate turnover in Serbia of at least two undertakings concerned is at least EUR 20m in the year preceding the

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concentration, and each of at least two of the undertakings concerned achieved a turnover in Serbia of at least EUR 1m.

The CC is obliged to decide within one month from the receipt of a complete merger notification whether to clear the transaction in summary proceedings or to initiate investigation proceedings. Should the CC decide to open investigation proceedings, it has to ultimately decide whether to (unconditionally or conditionally) clear or prohibit the transaction within four months from the date of initiating investigative proceedings.

In certain cases, CC may allow for remedies proposed by the undertakings within the proceedings if it is of the view that such measures are sufficient, and as a result of such, the concentration will not restrict, distort or prevent competition.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

As stated in the answer to question 7.2 above, the distribution and transportation network of natural gas may be in private ownership, but existing networks are in the ownership of Srbijagas and such ownership right cannot be alienated, pursuant to the EA. The system operator (regardless of whether it is domestic or foreign), in principle, may acquire the ownership rights over the facilities of the gas network that it has constructed from its own funds, acquired in the business transaction or by incorporation or capital increase.

Pursuant to the Serbian Act on Investments, foreign investors are entitled to exactly the same regime, rights and obligations as those applicable to domestic investors. MGEA explicitly provides that geological explorations can be conducted by the foreign legal entities in line with that Act and the Serbian Act on Investments and in accordance with the laws governing the area of defence and confidentiality principles.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The regulatory policy in respect of the oil and natural gas sectors in Serbia is particularly influenced by the Treaty on Establishing the Energy Community 2005 (ratified by Serbia in July 2006) (EC Treaty). The EC Treaty sets the obligations and targets to parties in order of compliance with the *acquis communautaire* and creation of the integrated energy market, allowing for cross-border trades and integration with EU markets.

Also, Serbian regulatory policy is led by the Treaty on Stabilisation and Association to the EU (TSA), which entered into force on 1 September 2013. One of the main obligations undertaken by Serbia under the TSA is the transposition of the EU legislative and regulatory framework into domestic law.

Pursuant to the EC Treaty and TSA, Serbia has harmonised its oil and natural gas legislation with, *inter alia*, the oil-related EU directives and the Third Energy Package. Also, the respective regulatory policy is governed by the inter-governmental treaties entered into by the Serbian Government (e.g. the abovementioned agreements with the Russian Federation).

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

There are no compulsory dispute resolution procedures prescribed by the applicable legal acts. The parties are in principle entitled to negotiate and agree on the dispute resolution mechanisms. Notably, the model agreements under the Codes provide for dispute resolution before the competent local court. Presumably, the foreign investor may request arbitration from the system operators. Pursuant to the PPP Act, the parties may agree on domestic or foreign arbitration in the concession agreement, whereby the foreign arbitration may be contractually agreed only if a private partner, or its direct or indirect shareholder is a foreign legal entity or individual, i.e. in case of consortium, if at least one member of a consortium or its direct or indirect shareholder is a foreign legal entity or individual.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Yes, both the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the Convention on the Settlement of Investment Disputes between States and Nationals of Other States have been duly ratified into Serbian legislation on 12 March 2001 and on 9 May 2007, respectively.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

Generally, there is no special difficulty in litigating or seeking to enforce judgments or awards against Government authorities. However, due to the general administrative hurdles in Serbian judicial practice and rather lengthy processes, the companies often try to resolve the dispute amicably and without seeking judicial remedy.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are aware of numerous successful commercial litigation and administrative dispute cases resolved in favour of energy companies before the local courts.

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14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Pursuant to the EC 2017 Implementation Report, Serbia is identified as 'the most advanced Contracting Party in terms of transposition and implementation of the oil *acquis*'. The legal framework for oil stocks is in place and Serbia has established a central stockholding body. The Ministry has engaged in development of emergency oil and oil derivatives stock of the Republic of Serbia, which is to be implemented through public-private partnership under the PPP Act.

There are certain indicators and market speculations that the project of development of the South Stream will be resumed. No official information is announced yet.

Full legal and functional unbundling of Srbijagas remains the key issue and drawback in Serbia's progress and alignment with its international and national obligations, which aim to secure an integrated gas network to the benefit of Serbian customers. The EC 2017 Implementation Report has concluded a total lack of progress in Serbian gas market reforms, and it has also confirmed the low level of enforcement of national gas legislation.

The inter-governmental agreement concluded in 2012 between Serbia and Russia for natural gas supply contained a controversial 'destination clause', which limited natural gas supplies only to the Serbian market, based on which the agreement was subject to an infringement procedure by EC and a process initiated against Gazprom by the European Commission for the infringement of competition rules. Based on the Protocol on amendments signed by the end of 2017 between the two countries, the 'destination clause' is annulled, whereas such amendment is yet to enter into force following the ratification procedure in both countries.

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Moravčević, Vojnović and Partners in cooperation with Schoenherr has been active in the Serbian market since 2002. The firm's practice is client-orientated, with specialised practice groups that provide industry-focused services to meet the demands of a competitive, developing and rapidly changing marketplace. The firm's client list includes leading companies, financial institutions, organisations and governments. With 40 lawyers, Moravčević Vojnović and Partners in cooperation with Schoenherr has the capacity to provide legal advice across practices and industries. In addition to the Serbian practice, Moravčević Vojnović and Partners in cooperation with Schoenherr is frequently engaged in high-profile transactions in Bosnia and Herzegovina, Montenegro and Macedonia.

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South Africa

David Forfar

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

South Africa's oil and gas resources are relatively undeveloped. South Africa is a small but growing competitor in the oil and natural gas industry. According to BMI Research, South Africa has estimated proven oil reserves of only 13.8mn barrels (bbl) and 28.8bn cubic metres (bcm) of proven gas reserves.

Exploration activities in South Africa have led to the discovery of oil and gas fields and to the commercial production of oil and gas in the Bredasdorp Basin. In the Pletmos Basin, two gas fields and a further six gas discoveries are undeveloped. One oil and several gas discoveries have been made off the West Coast of South Africa in the Orange Basin. One of these discoveries is the Ibhubesi Gas Field in Block 2A which contains an estimated 15.3 bcm of gas and 4.3mn bbl of condensate and is currently under development. Sunbird Energy (Ibhubesi) Pty Ltd ("Sunbird") is the operator of the block and holds a 76% interest in the relevant production right, with The Petroleum Oil and Gas Corporation of South Africa ("**PetroSA**") holding the remaining 24%.

With the availability of natural gas in neighbouring countries such as Mozambique, and the discovery of offshore gas reserves in South Africa, the gas industry in South Africa is undergoing rapid expansion. Future development of regional gas fields will lead to natural gas becoming a more important source for meeting South Africa's energy requirements.

PetroSA owns and operates a gas-to-liquids plant at Mossel Bay. PetroSA is also involved in oil and gas exploration and production, and its offshore production platform supplies gas and condensates by pipeline to its onshore plant for conversion into a range of transportation fuels and associated products. On 2 September 2017, PetroSA and the Russian exploration company Rosgeo entered into a USD 400m deal in terms of which Rosgeo will conduct exploration work to help develop blocks 9 and 11a off South Africa's southern coast. The exploration work will include the drilling of exploration wells as well as the shooting of more than 4,000 km² of 3D seismic surveys and 13,000 m of gravity-magnetic surveys.

Transnet Pipelines owns, operates, manages and maintains a network of 3,000 km of high-pressure petroleum and gas pipelines, on behalf of the South African Government.

Further, iGas (a State-owned entity established for the purpose of developing South Africa's gas infrastructure) partnered with Sasol and ENH of Mozambique in establishing the natural gas pipeline from Mozambique to South Africa.

A National Gas Infrastructure Development Plan has been drafted to provide the Government with a blueprint for the development of an infrastructure framework for future gas market developments.

South Africa has four conventional refineries and three synfuel plants with an overall refining capacity of 703,000 barrels per day (b/d).

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

South Africa's primary energy source is coal. According to the BP Statistical Review of World Energy, in 2016 coal constituted approximately 85.1% of South Africa's primary energy consumption followed by crude oil at 26.9%, natural gas at 4.6%, nuclear at 3.6%, renewables at 1.8% and hydro-electricity at 0.2%.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

South Africa has limited natural gas reserves and limited import and storage facilities. BMI estimates for 2016 put dry natural gas production at 0.7 bcm and consumption at 4.7 bcm, totalling an import of 4 bcm. BMI forecasts for 2017 predict dry natural gas production of 0.7 bcm and consumption of 4.9 bcm. Most of the imports are via pipeline from Mozambique.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

South Africa does not export natural gas or oil.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

See question 1.1 above.

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2.2 To what extent are your jurisdiction's energy requirements met using oil?

See question 1.2 above.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

South Africa has no significant crude oil production. BMI Research estimates that South Africa will only produce 2,740 b/d of crude oil in 2017, with the bulk of the output coming from Oribi, Oryx and Sable fields in the Bredasdorp Basin. It is, however, estimated that South Africa will produce a further 144,240 b/d of synthetic fuels produced from coal and natural gas. It is estimated that consumption for the same period will reach 646,600 b/d. Consequently, in 2017, approximately 23% of South Africa's oil requirements will be met through domestic production.

2.4 To what extent is your jurisdiction's oil production exported?

See question 1.4 above.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The principal legislation governing the exploration and production of oil and natural gas is the Mineral and Petroleum Resources Development Act 28 of 2002 ("**MPRDA**").

Petroleum resources belong to the nation while the State, via the Minister of Mineral Resources ("**the Minister**"), acts as the custodian thereof. The Minister is responsible for regulating and promoting petroleum development in South Africa and is empowered to grant or refuse applications for reconnaissance permits, technical co-operation permits, exploration rights and production rights and may initiate "licensing rounds".

The Petroleum Agency of South Africa ("**PASA**") is responsible for promoting and regulating exploration for, and exploitation and production of petroleum. In general, it performs an advisory and administrative role which includes receiving, evaluating and making recommendations to the Minister on applications for petroleum permits and rights and monitoring compliance with permits and rights.

Please also see section 14 below.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Access to petroleum resources may be obtained by submitting an application to PASA for a reconnaissance permit, technical co-operation permit, exploration right or production right. Alternatively, the State may announce a licensing round in terms of which exploration and production rights in respect of a block, or blocks, may be acquired following the submission of bids.

In terms of the Mining Titles Registration Act 16 of 1967, exploration and production rights must be registered with the Mineral and Petroleum Titles Registration Office ("**MPTRO**") at which stage they will constitute limited real rights. Reconnaissance permits and technical co-operation permits need only be recorded by, and filed with, the MPTRO.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The holder of a reconnaissance permit may carry out operations for, or in connection with, the exploration for minerals or petroleum by geological, geophysical and photo-geological surveys, as well as any remote sensing techniques. The holder of a reconnaissance permit may not, however, carry out any prospecting or exploration activities. A reconnaissance permit is valid for a year and is not renewable or transferable, nor does it grant the holder any exclusive rights.

The holder of a technical co-operation permit may carry out a technical co-operation study in accordance with a technical co-operation work programme, which may include desktop studies but not any exploration or production activities. The holder of a technical co-operation permit has an exclusive right to apply for, and be granted, an exploration right over the area described in the permit subject to certain terms and conditions. Technical co-operation permits are valid for one year and are not renewable or transferable.

The holder of an exploration right may conduct exploration activities, which means the re-processing of existing seismic data, the 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. An exploration right is valid for the period specified in the right, which period may not exceed three years. Exploration rights, which are transferable, may be renewed for a maximum of three periods not exceeding two years each. Subject to certain terms and conditions, the holder of an exploration right has the exclusive right to apply for, and be granted, a production right in respect of the petroleum and the exploration area in question.

The holder of a production right may conduct production operations which are defined as any operations, activities or matters that relate to the exploration, appraisal, development and production of petroleum. Production rights are transferable and are valid for the periods specified in each right, which period may not exceed 30 years, and may be renewed for further periods, each of which may not exceed 30 years at a time.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

State participation is not legislated but is provided for in the standard form exploration and production rights, which stipulate that the Government has an option to acquire a 10% participating interest in a production right through an organ of the State. Neither the law nor the rights provide that the State has a right to participate as the operator of the right. The State is usually not liable for past expenditure but must

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contribute in proportion to its participating interest to production costs incurred subsequently to the acquisition of the interest.

Please also see section 14 below which deals with proposed amendments to the MPRDA which may introduce, amongst other things, a 20% free carried interest for the State in all new exploration and production rights.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Royalty

The Mineral and Petroleum Resources Royalty Act 28 of 2008 ("**the Royalty Act**") provides for the imposition of a royalty on the "transfer" of mineral resources extracted from within South Africa.

Royalties are payable when mineral resources extracted from within South Africa are "transferred", which includes the disposal or consumption thereof. Royalties are calculated in terms of a particular formula and the maximum royalty percentage is capped at 5% for refined mineral resources and 7% for unrefined mineral resources.

The Royalty Act authorises the Minister of Finance to conclude binding fiscal stability agreements with an extractor in respect of an existing mineral resource right (which includes petroleum rights) or in anticipation of the extractor acquiring a mineral resource right. These agreements offer some measure of long-term fiscal stability as it ensures that royalties will not be imposed at a rate which is greater than the royalty rate at the time when the extractor entered into the fiscal stability agreement.

Tax

The main taxes being imposed are income tax and capital gains tax ("**CGT**") imposed in terms of the Income Tax Act 58 of 1962 ("**the ITA**"), and Value Added Tax ("**VAT**") chargeable in terms of the Value Added Tax Act 89 of 1991 ("**the VAT Act**"). Other taxes include, for example, transfer duty on the transfer of immoveable property and securities transfer tax on the transfer of securities (e.g., shares). The South African Revenue Service ("**SARS**") is tasked with collecting revenue and ensuring compliance with tax laws.

The Tenth Schedule to the ITA deals specifically with the taxation of oil and gas companies and contains a number of favourable provisions applicable specifically to oil and gas companies (i.e., companies holding an oil and gas right) in respect of oil and gas income. For example, an oil and gas company may claim a 100% uplift in respect of capital expenditure in respect of exploration, and a 50% uplift in respect of capital expenditure in respect of post-exploration. The Tenth Schedule further authorises the Minister of Finance to conclude a binding fiscal stability agreement ("**FSA**") with an oil and gas company which guarantees the continued application of the Tenth Schedule in respect of the specific oil and gas right. An oil and gas company may, on disposal of an exploration or production right and as part of such disposal, assign all of its fiscal stability rights in terms of an FSA to another oil and gas company in such circumstances as stipulated in the Tenth Schedule. Where two companies jointly hold an exploration right and one of them has concluded a FSA, the fiscal stability rights in terms of that FSA will apply in respect of both of those companies.

3.6 Are there any restrictions on the export of production?

An export permit in terms of the International Trade Administration Act 71 of 2002 ("**the ITA Act**") is required for the export of petroleum products.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Exchange controls could potentially impact on the currency of transactions and on the transfer of funds, depending on the identity of the parties and the nature of the transactions. South African residents are subject to exchange controls, with the purpose of, *inter alia*, regulating inflows and outflows of capital from South Africa. Whilst non-residents are in principle not subject to South African exchange control restrictions, non-residents may in specific instances be required to comply with certain requirements from a compliance perspective. Non-residents should take into account the fact that their South African counterparts may need to apply for exchange control approval for certain types of transactions and/or may need to comply with certain formalities. If exchange control approval is required for a transaction, the non-resident would have to consider whether the agreement between the parties should provide for such approval to be a condition precedent. In respect of currency exchange restrictions, if an agreement is between two exchange control residents (e.g. a South African incorporated company and the South African branch of a foreign incorporated company), the currency would, as a general rule, have to be South African Rand ("**ZAR**"). Where the transaction is between a resident and a non-resident, it may be denominated in foreign currency, although a resident exporter may be required to convert the foreign funds to ZAR within 30 days of receipt.

The remittance of funds derived from production in South Africa would require the fulfilment of certain compliance requirements. For example, the remittance of dividends by a South African company to a foreign shareholder would, as a general rule, require the "non-resident" endorsement of the shares held by the non-resident shareholder, and an audit certificate confirming that the dividends are declared from profits.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

An exploration or production right or any interest in such right, or a controlling interest in a company (other than a listed company) that holds such right, may not be ceded, transferred, let, sublet, assigned, alienated or otherwise disposed of without the written consent of the Minister. An application for the Minister's consent will essentially have to demonstrate that the transferee has the requisite technical and financial ability to comply with the obligations imposed on the holder of the exploration or production right.

One of the objects of the MPRDA is, in accordance with section 2(d), to "substantially and meaningfully expand opportunities of historically disadvantaged persons, including women and communities, to enter into and actively participate in the mineral and petroleum industries and to benefit from the exploitation of the nation's mineral and petroleum resources". When an application is made to the Minister for the transfer of an exploration right, the Minister may request that the applicant give effect to the object referred to in section 2(d). Similarly, an applicant for a production right will have to satisfy the requirement that it will be able to further the object referred to in section 2(d).

The encumbrance by mortgage as security to obtain a loan or guarantee for the purpose of funding or financing an exploration or production project by certain banking or financial institutions does not require the consent of the Minister, provided that the bank or financial institution in question undertakes, in writing, that any sale in execution or any other disposal pursuant to the foreclosure of the mortgage will be subject to Ministerial consent.

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3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

The MPRDA requires that financial provision be provided, guaranteeing sufficient funds to cover the proposed work programme commitments. The form of such guarantee needs to be acceptable to the Petroleum Agency SA.

Additionally, in accordance with the National Environmental Management Act 107 of 1998 ("**NEMA**"), companies are required to make financial provision for the rehabilitation and management of potential negative environmental impacts.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

It is possible to mortgage petroleum rights under South African law.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Exploration and production activities cannot commence without an environmental authorisation granted in terms of the NEMA, prior to the granting of which an environmental impact assessment investigating the potential impact of the proposed activity must be conducted.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

In terms of the NEMA, right holders are required to apply for a closure certificate upon the lapsing, abandonment or cancellation of the right, cessation of exploration or production operations, or in respect of any relinquished portion. The Minister of Mineral Resources issues the closure certificate after having considered such application.

When issuing the closure certificate, the Minister may retain such portion of the financial provision as may be required to rehabilitate the closed production or exploration operation in respect of latent, residual or any other environmental impacts, including the pumping of polluted or extraneous water, for a prescribed period.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

The Gas Act 48 of 2001 ("**the Gas Act**") provides the primary legislative framework for the storage of gas. In terms of the Gas Act, no person may, without a licence issued by the National Energy Regulator ("**the Regulator**"), construct or operate gas storage facilities. Storage facility licences are subject to third-party access to uncommitted capacity on commercially reasonable terms.

The Regulator has the power to determine whether any person is engaged in gas storage and other activities. If they are conducting such activities without a licence, the regulator can direct the party to cease operating.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

The import of natural gas is regulated primarily by the ITA Act. A permit is required in order to import petroleum gas and other gaseous hydrocarbons. Bearing in mind that South Africa does not currently export natural gas, there is currently no legislated position on the export of natural gas.

Furthermore, the Gas Act requires an owner of an operation involving the importation of gas to register with the Regulator.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

The import and export of oil and oil products is regulated by the ITA Act and the Guidelines Governing the Recommendations by the Department of Minerals and Energy to the International Trade Administration Commission in respect of the Importation and Exportation of Crude Oil, Petroleum Products and Blending Components ("**Import and Export Guidelines**").

An import permit is required for the importation of crude oil, petroleum products and blending components. Only licensed wholesalers owned and controlled by historically disadvantaged South Africans and licensed manufacturers may apply for a licence to import petroleum products and blending components, whereas any person may apply for a licence to import crude oil. Any licensed wholesaler and licensed manufacturer may apply to import liquefied petroleum gas.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

The pipeline network in South Africa is not well developed as, to date, only relatively insignificant quantities of oil and gas have been discovered. The main pipeline network is the Rompco Pipeline, which is used to transport gas from Mozambique to South Africa.

Existing pipelines are generally constructed, owned and operated by private companies, subject to certain licensing requirements which are discussed in question 6.2 below. The South African Government has set up a State-owned company, iGas, to enter into joint ventures for gas transmission pipelines and related projects (this company holds a 25% equity stake in the Rompco pipeline).

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The pipeline transportation of oil and natural gas are respectively

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regulated by the Petroleum Pipelines Act and the Gas Act. A licence is required in terms of the Gas Act to construct and/or operate gas transmission, storage, distribution, liquefaction and re-gasification facilities. Similarly, a licence is required in terms of the Petroleum Pipelines Act to construct and operate petroleum pipelines, loading facilities and storage facilities. Both of these licences are issued by the Regulator.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Generally, access to land is negotiated through agreements concluded with the land owners. The Regulator has the power to expropriate land or rights in land if either cannot be acquired through negotiation with land owners or if the land is reasonably required for the construction of facilities which will enhance the Republic's petroleum or gas infrastructure.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Since the majority of infrastructure is privately owned, access is organised through commercial contracts between the owner of the pipeline and the company seeking access. This is subject to the requirements discussed in question 6.6 below.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

As mentioned above, South Africa's pipeline network is not well developed and therefore there is, as yet, little integration and interconnection of systems. These requirements would be regulated through the relevant licensing regime discussed in question 6.2.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Under the Gas Act and the Petroleum Products Act, the Regulator can compel licensees to provide third-party access to transportation and storage infrastructure by imposing licence conditions.

In terms of the Gas Act, operators of a transmission pipeline and the owners of storage facilities must provide access to uncommitted capacity, but cannot be compelled to expand their facilities. Grounds for refusal are limited to inadequate uncommitted capacity, technical feasibility and commercial viability.

In terms of the Petroleum Products Act, pipeline and loading facility capacity must be shared among all users in proportion to their needs and within the commercial and operational constraints of the pipeline, subject to payment to reserve the capacity as a condition of service. Owners of storage facilities must provide access to uncommitted capacity, but cannot be compelled to expand their facilities.

Where costs are occasioned as a result of modifying the network or storage facility, under both the Gas Act and the Petroleum Products Act, the licensee is not obliged to incur additional costs and the total cost of the pipeline or storage facility must be shared equitably between the licensee and the party requesting the change.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

The Regulator sets tariffs for petroleum pipelines based on a range of factors aimed at balancing the interests of operators and consumers. Parties can agree between themselves tariffs for the use of storage and loading facilities pertaining to petroleum as well as gas transmission and storage facilities; however, approval of the Regulator is required.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Currently, gas plays only a minor role in South Africa's energy mix but this is likely to change as South Africa's energy policies project that gas will play an increasingly important role.

Sasol is currently the only major distributor of gas in South Africa, importing in excess of 100 million gigajoules of natural gas *per annum* from the Pande and Temane gas fields in Mozambique. Consequently there is limited transmission and distribution infrastructure for piped gas, which is owned primarily by Sasol, iGas and the Government of Mozambique.

Sasol, together with the Mozambican and South African Governments, is in the process of constructing an additional 127 km loop line parallel to the existing pipeline that is currently used for the importation of gas from Mozambique. The loop line is expected to increase gas importation capacity by 12.5%.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

A licence is required to construct and operate gas distribution facilities, arising from the Gas Act. Certain land use planning approvals and environmental authorisations may also be required depending on the nature and extent of the facilities.

7.3 How is access to the natural gas distribution network organised?

The natural gas transmission network is predominantly owned by private entities as stated in the response to question 6.4 above. Access is consequentially organised between the owner and the party seeking access.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Although distributors cannot be compelled to grant access to,

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or expand, their capacity, operators of transmission lines can be compelled to grant access to uncommitted capacity.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Fees to access the distribution network are determined on a commercial basis but, where there is inadequate competition and a party has a dominant position, the Regulator has the power to approve maximum prices for distributors.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Where the interest or assets are being sold by a State-owned entity, they may only be disposed of by means of an open and transparent bidding procedure.

The sale of assets forming part of the distribution network would be subject to the new owner obtaining a licence to operate them from the Regulator.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

In order to trade in natural gas, a trading licence is required and the applicant must submit an application in the prescribed form to the Regulator.

In addition, the Gas Act requires an owner of an operation involving the importation of gas to register with the Regulator.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

The Gas Act, which dictates that a trading licence is required for the trading of gas, defines "**gas**" as "all hydrocarbon gases transported by pipeline, including natural gas, artificial gas, hydrogen rich gas, methane rich gas, synthetic gas, coal bed methane gas, liquefied natural gas, compressed natural gas, re-gasified liquefied natural gas, liquefied petroleum gas or any combination thereof […]".

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

As stated in response to question 7.1 above, gas has a relatively small stake of the energy mix in South Africa. The Government, however, has recently taken initiatives towards LNG imports as a means to diversify the energy mix and decrease coal-dependence.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The Gas Act provides that licences are required for the construction and operation of liquefaction or re-gasification facilities or the conversion of existing infrastructure into such facilities, as well as the operation of such facilities and trading in gas, including LNG.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The Regulator may set the maximum prices for distributors, reticulators, and all classes of consumers, where there is inadequate competition in the gas industry.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

There are no third-party access rights to liquefaction or re-gasification facilities.

As regards transmission and storage facilities pertaining to LNG, please see the response to question 6.6 above.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream sector is regulated by the Petroleum Products Act 120 of 1977 ("**PPA**"). In terms of the PPA, a person may not manufacture, wholesale, hold or develop a site for, or retail, prescribed petroleum products without an applicable licence. The Controller of Petroleum Products has the authority to direct the cessation of any such activities being conducted without the applicable licence.

Additional health and safety, and environmental land use planning requirements may be applicable.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

There are no special requirements relating to the trade in oil as a commodity in South Africa.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The Competition Commission (the "**Commission**"), the Competition Tribunal (the "**Tribunal**") and the Competition Appeal Court are the governmental authorities established in terms of the Competition Act 89 of 1998 (the "**Competition Act**"). The Competition Act applies to "all economic activity within, or having an effect within, the Republic [of South Africa…]".

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Broadly, the Competition Act prohibits vertical restrictive practices (anti-competitive conduct between a firm and its suppliers, its customers or both), horizontal restrictive practices (anti-competitive conduct between competitors) and the abuse of dominance.

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Section 4(1) of the Competition Act states that an agreement between, or concerted practice (being co-operative or co-ordinated conduct between firms, achieved through direct or indirect contact, that replaces their independent action but which does not amount to an agreement) by firms, or a decision by an association of firms, is prohibited if it is between parties in a horizontal relationship and if:

- it has the effect of substantially preventing or lessening competition in a market, unless a party to the agreement, concerted practice or decision can prove that any technological, efficiency or other pro-competitive gain resulting from it outweighs that effect (this is set out in section 4(1)(a)); or
- it involves any of the following restrictive horizontal practices (this is set out in section 4(1)(b)): directly or indirectly fixing a purchase or selling price or any other trading condition; or dividing markets by allocating customers, suppliers, territory, or specific types of goods or services, or collusive tendering.

Notably, for the purposes of the Competition Act, an agreement includes a contract, arrangement or understanding, whether or not legally enforceable.

Section 4(1)(b) of the Competition Act refers to restrictive horizontal practices that are *per se* unlawful. This means that no pro-competitive gains or other justifications may be raised as a "defence".

Section 4(1)(a) of the Competition Act addresses restrictive horizontal practices that are subject to a "rule-of-reason" analysis. This means that the pro-competitive effects of an agreement or practice between competitors must be weighed up against, and must off-set, the anti-competitive effects in order for the agreement or practice to be lawful.

Section 5(1) of the Competition Act provides that an agreement between parties in a vertical relationship is prohibited if it has the effect of substantially preventing or lessening competition in a market, unless a party to the agreement can prove that any technological, efficiency or other pro-competitive gain resulting from that agreement outweighs that effect. Put differently, agreements to which section 5(1) of the Competition Act applies are subject to a "rule-of-reason" analysis.

Section 5(2) of the Competition Act prohibits the practice of minimum resale price maintenance between parties in a vertical relationship as *per se* unlawful.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The Competition Act confers broad investigative powers on the Commission, including the power to subpoena any person who is believed to be able to furnish any information or to be in possession or control of any document or other object that has a bearing on the subject of an investigation conducted by the Commission. Additionally, the Commission has broad powers of search and seizure and has conducted a number of dawn raids in various industries.

Further, administrative penalties of up to 10% of a firm's turnover in South Africa and its exports from South Africa may be imposed on a firm found to have contravened the Competition Act.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

As mentioned in question 11.1 above, the Competition Act applies to the oil and gas sector. As such, any transaction in this sector is required to be notified to the Commission and approved by the competition authorities before it is implemented if it: (i) constitutes a merger (as defined in section 12 of the Competition Act); (ii) meets the thresholds (of assets and turnover) set out in the Competition Act; and (iii) constitutes economic activity within, or having an effect within, South Africa.

Section 12 of the Competition Act states that a transaction constitutes a merger when "one or more firms directly or indirectly acquire or establish direct or indirect control over the whole or part of the business of another firm". A person controls another firm if that person, amongst other things:

(a) beneficially owns more than one-half of the issued share capital of the firm;

(b) is entitled to vote a majority of the votes that may be cast at a general meeting of the firm, or has the ability to control the voting of a majority of those votes, either directly or through a controlled entity of that person;

(c) is able to appoint or to veto the appointment of a majority of the directors of the firm;

(d) is a holding company, and the firm is a subsidiary of that company as contemplated in section 1(3)(a) of the Companies Act; or

(e) has the ability to materially influence the policy of the firm in a manner comparable to a person who, in ordinary commercial practice, can exercise an element of control referred to in (a) to (d) above.

The Competition Act, therefore, contemplates that the acquisition or sale of assets which constitute the whole or part of the business of another firm, gives rise to a merger. Such assets may therefore include exploration and/or production rights.

From a threshold perspective, there are two categories of notifiable mergers; namely, intermediate mergers and large mergers. Small mergers are those that fall below the prescribed thresholds and are not notifiable in the ordinary course.

Intermediate mergers are those that meet the following thresholds:

1. the combined annual turnover in, into or from South Africa of the acquiring firm/s and the target firm/s (described below) are valued at R600 million or more; or
2. the combined assets in South Africa of the acquiring firm/s and the target firm/s are valued at R600 million or more; or
3. the annual turnover in, into or from South Africa of the acquiring firm/s plus the assets in South Africa of the target firm/s are valued at R600 million or more; or
4. the annual turnover in, into or from South Africa of the target firm/s plus the asset/s in South Africa of the acquiring firms are valued at R600 million or more.

In addition, the annual turnover in, into or from South Africa or the asset value of the target firm/s must be R100 million or more.

A large merger is one where one of the four calculations given above results in a figure that is equal to or exceeds R6.6 billion and the turnover or asset value of the target firm/s equals or exceeds R190 million. Please note that the turnover and assets should be calculated with reference to the previous financial year of the parties, and (in short) are the gross turnover (revenue) and assets of the firm (calculated in accordance with GAAP/IFRS).

The review period for intermediate mergers comprises an initial period of 20 business days (excluding the first day, but including the last). This period may be extended by a single period not exceeding 40 business days.

In the case of large mergers, the Commission must, within 40 business days, forward to the Tribunal a written recommendation, with reasons, regarding the merger. This period is extendable with

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the consent of the Tribunal by periods of no more than 15 business days at a time.

When the Commission has forwarded a recommendation to the Tribunal, the Registrar of the Tribunal must schedule a date within 10 business days for either the beginning of the hearing of the matter or for a pre-hearing conference in relation to the large merger (should the circumstances require). This period of 10 business days may be extended for a further 10 business days by the Chairperson of the Tribunal or for a further period by the Chairperson with the consent of the parties. After completing its hearing in respect of a merger, the Tribunal must issue its decision within 10 business days after the end of the hearing and within 20 business days thereafter issue written reasons for its decision.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

No, there are no special requirements or limitations as such. Foreign companies, however, operating and conducting business in South Africa are subject to the laws and regulations pertaining to the Government's economic transformation policies which it implements principally through the Broad-Based Black Economic Empowerment Act 53 of 2003. The purpose of such policies is to increase the number of black people that manage, own and control the country's economy, which may, thus, prescribe local content requirements on ownership.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

South Africa is a signatory to a number of international treaties and multinational agreements which impact on the interpretation and application of its domestic laws, including, amongst others, the United Nations Convention on the Law of the Sea. Notably, the Constitution of South Africa, which is the supreme law of the country, directs South African courts to prefer any reasonable interpretation of legislation that is consistent with international law over any alternative interpretation that is inconsistent with international law.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Although disputes may be brought before local courts, arbitration is the preferred dispute resolution mechanism for parties to commercial disputes. Dispute resolution clauses in upstream-related rights, as well as dispute resolution clauses in midstream and downstream contractual arrangements, usually provide for disputes to be settled by way of arbitration in accordance with the rules of the Arbitration Foundation of Southern Africa.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

South Africa is a party to the New York Convention, which has been enacted into domestic legislation by way of the Recognition and Enforcement of Foreign Arbitral Awards Act 40 of 1977. South Africa is not party to the ICSID.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

In terms of the Institution of Legal Proceedings Against Certain Organs of State Act 40 of 2002, a notice of intention to institute legal proceedings must be served on an organ of the State within six months from the date on which a cause of action arose. Any court process by which legal proceedings are instituted may not be served on the State before the expiry of 30 days after the notice of intention to institute legal proceedings was served on the organ of the State.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are not aware of any judgments or awards obtained by foreign corporations against Government authorities or State organs in the oil and natural gas sector. Foreign corporations are, however, not precluded from doing so.

Local subsidiaries of foreign corporations have obtained judgments against the State in mining and other sectors.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

In late 2016, the National Council of Provinces ("**the NCOP**"), one of the two houses of parliament, convened a committee to discuss possible amendments to the MPRDA Bill B15 of 2013 ("**the Bill**") which, if passed and assented to, will amend the MPRDA. The Bill proposes several wide-ranging changes to the upstream regulatory framework, especially as they relate to the participation by the State and historically disadvantaged South Africans. One of the proposed amendments to the Bill that has been tabled before the NCOP by the Department of Mineral Resources ("**the DMR**") is the deletion of those clauses of the Bill that would do away with the Petroleum Agency of South Africa ("**PASA**") as the body responsible for managing the licensing and promotional aspects of the upstream

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industry. In addition to the retention of PASA, a noteworthy amendment to the Bill that has been proposed by the DMR for consideration by the NCOP is the development of an upstream-specific Broad-Based Socio-Economic Empowerment Charter ("**the Petroleum Charter**"). The proposed Petroleum Charter will do away with the idea of subjecting the upstream industry to the Mining Charter, a move which would have increased the minimum level of participation by black persons from the accepted position of 10% to the substantially higher position of 26%. A further significant amendment to the Bill is the revision of section 86A which proposes, amongst other things, a 20% free carried interest for the State in all new exploration and production rights. Under the revised version of section 86A, the State will have a right to a 20% carried interest in such rights and the holders of production rights will be entitled to recover the development costs associated with the State's carried interest from proceeds generated under their production rights. In other words, what has been proposed is the removal of free carry and the introduction of carried interest with a cost-recovery mechanism. Notably, the proposed amendments to section 86A of the Bill also provide for the downward adjustment of the State's carried interest in a production right to a figure that is not less than 10%. Such adjustment will require consultation with the Minister of Finance and consideration of, amongst other things, the nature and scope of this particular project.

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Turkey

Levent Çelepçi

Türkoğlu & Çelepçi in cooperation with Schoenherr

Murat Kutluğ

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

Turkey has very limited natural gas resources, as a result of which the internal consumption requirement is almost exclusively met with imported gas, be it in the form of pipeline gas or LNG. Turkey's main import partner is Russia, which is the source of 53% of imported gas. Pipeline gas constituted 84%, while LNG represented 16% of total imported gas in 2016.

Due to limited production, a very small quantity of gas is exported, with one single destination, which is Greece.

Currently, storage capacity corresponds to less than 10% of annual imported quantity.

The main market player in the gas market is the State-owned Boru Hatları İle Petrol Taşıma A.Ş. ("**BOTAŞ**"), which has realised approximately 84% of the total gas imported into the country in 2016.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Although declining, natural gas still plays an important role in terms of Turkey's energy requirements. 38% of total electricity production was based on natural gas in 2017, while hydroelectric accounted for 20%, coal 33% and wind power 6%.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Domestic gas production in Turkey is quite limited, covering approximately 1.2% of total consumption. Turkey's gas requirements are mainly met through imported gas. The main countries from which gas is imported into the country are the Russian Federation (53%), Iran (17%), Azerbaijan (14%), Algeria (10%) and Nigeria (3%).

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

As a natural consequence of the fact that Turkish natural gas production is very limited and the internal consumption requirement can only be met through imported natural gas, Turkey exports a relatively small quantity to Greece. The quantity exported in 2016 amounts to 0.6 bcm. Currently, there are nine licensed legal entities having an export licence, and the only one which was active in 2016 was BOTAŞ.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

Domestic oil consumption in 2016 was approximately 26.7 million tons, which marked an increase of 7.6% compared to the previous year, and is expected to increase in upcoming years. Given the very limited amount of oil production (around 7% of total demand), such demand is being met by imported oil to a great extent.

It is expected that demand for oil will grow in alignment with GDP growth.

Currently, the Turkish Petroleum Company ("**TPAO**") is a major player in the oil exploration process. The liberalisation of the petroleum sector was evidenced by the Petroleum Law dated 11 June 2013 ("**Petroleum Law**"), which introduced several incentives for oil exploration. The new law is set to liberalise upstream activities by limiting the dominant market position of the TPAO.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

The percentage of domestic energy needs met by oil (including LPG) is 28%. It is foreseen that the share of oil will remain relatively stable until at least 2023, when the share of oil is predicted to be around 26%.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

Domestic production covers 7% of internal demand. Turkish crude oil reserves reached 312 million barrels in 2014, marking a slight increase from 296 million barrels in 2013. In the event that no new discoveries are made, and based on current production/consumption statistics, the existing crude oil reserves will be exhausted in 17 years.

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2.4 To what extent is your jurisdiction's oil production exported?

Although Turkey's production of liquid fuels has increased since 2004, it is much less than what the country consumes each year. TPAO is the dominant exploration and production entity in Turkey. In 2013, TPAO produced 34,000 b/d of crude oil, accounting for 73% of the total crude oil production in Turkey. Petroleum products exported reached 9,286,007 tons, marking an increase of 11.28% compared to 2013.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Oil and gas exploration and exploitation activities, which constitute upstream activities, are generally regulated under the Petroleum Law. It should always be noted that Turkey is a contracting party to many conventions and international agreements with regards to the international oil and gas market. In this respect, certain international agreements to which Turkey is a party include the International Convention on Readiness, Response and Cooperation With Regards To Oil Pollution and Its Annexes dated 27 November 1992 (London) and the International Agreement on Establishment of an International Fund Regarding the Indemnification of the Damages Caused by Oil Pollution dated 27 November 1992 (London).

The General Directorate of Petroleum Affairs ("**GDPA**") is the relevant authority in respect to upstream activities, including exploration and exploitation permitting processes.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

All oil and natural gas resources in Turkey are owned by the State. Through a licensing system managed by GDPA, specific licences are granted to applicant companies. Please refer to the responses under question 3.3 below for further explanations on different types of licences. Such licences are subject to administrative laws and regulations. The Council of State has jurisdiction, as a court of first instance, in respect to challenges brought against decisions of the Ministry of Energy and Natural Resources ("**MENR**"), which reviews objections and disputes with respect to the issuance of such licences or their implementations.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The Petroleum Law sets forth that a research permit shall be issued by GDPA, which would entitle its holder to carry out certain research activities. The exploration and/or operation licences issued for a part of the area for which a research permit is requested do not constitute an obstacle for research permit issuance. The research permit applicant shall pay TL 0.5 per hectare within 60 days following the commencement of the review process of GDPA. Additionally, if the application is deemed to be acceptable, the applicant shall further deposit to GDPA a guarantee in the amount of 0.05% of the research permit charge per hectare within 15 business days following notification of the decision regarding the application. In the case that said amounts are not deposited in due time, the applicant will be deemed to have withdrawn its application. Apart from the research permit, there are two main types of licences required for exploration and operation activities.

Exploration Licences

As for exploration licences, the first application made for an area shall be announced in the Official Gazette. Following this announcement, additional applications can be made before GDPA. The business and investment plans of the applicants (including the first applicant) must be submitted to GDPA within 90 days following the announcement. The applications shall be assessed by GDPA in accordance with the criteria provided under the implementation regulation. The exploration licence shall be announced in the Official Gazette, and within 30 days following this announcement, the exploration licence holder shall deposit another guarantee, namely an investment guarantee, in the amount of 2% of the investment amount for onshore activities and 1% of the investment amount for offshore activities. In the case that the said guarantee amount is not duly deposited, the licence shall be cancelled by GDPA.

Exploration licences shall be initially issued for a period of five years for onshore and eight years for offshore, with a possibility of extension up to nine years for onshore and 14 years for offshore exploration activities.

Operation Licences

In order to obtain an operation licence, an application must be made to GDPA. If the application is accepted, the applicant shall further deposit a guarantee in the amount of 0.5% of the operation licence charge per hectare to GDPA within 15 business days following notification of the decision. If the said amount is not deposited in due time, the applicant will be deemed to have withdrawn its application.

Exploration and operation licences can also be issued by an auction by GDPA. The relinquished areas can also be licensed with the auction method upon the consent of MENR.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

According to the Turkish Constitution, natural resources belong to the State, along with the right to explore and exploit these resources (*Article 168, Turkish Constitution*). The State can delegate these rights to persons or corporate bodies for a certain period of time.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Exploration and/or exploitation licence holders must pay as a royalty to the Turkish State 12.5% of the value of the petroleum they have produced. The royalty amount shall be calculated once the expenses (i.e. income tax, corporate tax, other applicable taxes and charges, etc.) are deducted from the market price of the

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produced petroleum. Furthermore, the total taxation of a company engaged in exploitation, together with taxes withheld on behalf of its shareholders, cannot exceed 55%.

3.6 Are there any restrictions on the export of production?

Petroleum right holders are entitled to export a certain amount of the petroleum and natural gas (35% for onshore and 45% for offshore) that they produce in fields discovered after 1 January 1980. The remaining part and the whole petroleum and natural gas produced in the fields discovered before 1 January 1980 shall be reserved for domestic use. The Council of Ministers has the authority to regulate the procedures and principles on the redetermination and implementation of these ratios.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

GDPA approval is required for right holders to transfer funds derived from their production. Prior to the transfer, rights holders shall deduct taxes, fees and royalties that are yet to be accrued.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

To transfer an upstream oil or gas licence, the licence holder (transferor) and transferee must jointly apply to GDPA. The rights covered by upstream licences are recorded in the oil registry, which is maintained by GDPA. Both of the parties must provide detailed documents, maps and information about the proposed transfer to GDPA for its consideration.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

There are two types of collaterals that are required under the Petroleum Law:

- Collateral for Investment: The Law requires an applicant for an exploration licence to provide a bond equal to 2% of the financial commitment in the business plan as submitted in the licence application. For offshore exploration where the financial investment would be higher, the rate is reduced to 1% of the total investment amount.
- Collateral for Loss and Damages: The payment of an additional collateral before obtaining a petroleum right in order to cover any potential loss and damages that may occur during the petroleum activities is compulsory. The rate for search permits is 0.0005% of the search charge, 0.0001% of the exploration licence charge for exploration licences, and 0.005% of the operation licence charge for operation licences.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Yes, rights to develop oil and natural gas reserves granted to a participant can be pledged for security subject to prior approval by GDPA. The pledges would need to be registered in the Petroleum Register kept by GDPA.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Entities active in the energy sector must obtain an environment licence and environment permit from the Ministry of Environment and Urban Planning (*Article 7, Environmental Permit and Licence Regulation published in the Official Gazette dated 10 September 2014, No. 29115*). Requirements for environment licences are determined by considering the activity of a given business. Collectively, these permits and licences contemplate:

- Emissions.
- Discharges.
- Dangerous material discharges.
- Waste collection.
- Recycling matters.

These environment permits and licences must be obtained before operations begin. They are different to the EIA reports and are related to a positive or negative decision from the Ministry of Environment and Urban Planning.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

There are no specific provisions in Turkish legislation addressing decommissioning requirements, although upstream licence holders are required to return the land to its former condition (*Article 22(3), Petroleum Law*). While legislation is silent on the decommissioning requirements, the obligation to comply with environmental rules remains, along with the obligation to avoid endangering society and the environment. When an entity operating in the upstream market wishes to decommission its facilities, the entity must arrange for its rights to be deregistered from GDPA's petroleum registry (*Article 21, Petroleum Law*).

If a licensee ceases its activities, it must notify the relevant authority three months before its suspension (*Article 18, Environmental Permit and License Regulation*).

Since decommissioning generally involves closing a place of business, the employer must also notify the relevant tax office of the decommissioning, as well as other institutions, such as the social security and district labour offices.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

Natural Gas Law No. 4646 ("**Natural Gas Law**") regulates the natural gas market in terms of import, transmission, distribution, storage, marketing, trade and the export of natural gas and the rights and obligations of all real and legal persons relating to these activities is the principal legislation in Turkey.

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4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Cross-border sales or deliveries of natural gas can be performed either by importing natural gas into Turkey or exporting natural gas from Turkey.

There are certain important limitations in terms of importing pipeline gas into Turkey. As a matter of fact, the Natural Gas Law prohibits companies, other than BOTAŞ, to import pipeline gas from those countries with which BOTAŞ has an existing supply contract. New import contracts from such countries will only become possible when BOTAŞ contracts expire.

The Natural Gas Law foresees a reduction of BOTAŞ' market share to below 20% of the total internal consumption of natural gas. In view of reaching such goal, BOTAŞ launches tenders from time to time for assigning part of its existing supply contracts. As a pre-requisite to participate in such tenders, applicants are required to hold an import licence and also obtain the preliminary consent of the selling entity. Despite the objective determined in the Natural Gas Law, in 2014, 79.77% of the imports (pipeline gas and LNG combined) have been done by BOTAŞ.

Legal entities that wish to export the natural gas imported or generated within the country abroad must also obtain an export licence from the Energy Market Regulatory Authority ("**EMRA**"). The company asking for a licence should prove that it has the technical and economical capability and inform on which country and by which transportation vehicles it shall export the natural gas, to provide a guarantee to the effect that the export process will not intervene in operation of the system nor satisfaction of the natural gas demand of the country and towards recovery of any loss or damage which may occur if the system security is violated by the company, and to provide insurance coverage as compulsory for the loss and damage.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

The Petroleum Law provides that there are no further additional licence requirements needed in respect of the cross-border sales or deliveries of oil and products for holders of oil refinery licences, oil distribution licences or bunker delivery licences.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

To build and operate pipelines, the following must be obtained:

- The necessary licence from the Turkish Energy Market Regulatory Authority.
- A construction licence from the relevant public authority.
- An Environmental Impact Assessment ("**EIA**") Report from the Ministry of Environment and Urban Planning.

Depending on the nature of the pipeline project, other additional requirements may be imposed, such as specific approvals from BOTAŞ.

Quality standard regulations outline the types of the materials which must be used to build the facilities and pipelines.

Parties involved in transporting oil and gas through Turkey via pipeline must obtain an authorisation certificate from EMRA.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

Please refer to question 6.1 above for the government authorisations required to construct and operate oil and natural gas transportation pipelines and the associated infrastructure.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

By private agreement, expropriation or by obtaining leasehold rights from the Government either through easements or land allocation permits. If the applicant has an exploitation licence, the authority to request the expropriation is GDPA; if the applicant has a transmission licence, the authority is EMRA. At the end of the expropriation process, the expropriated land is registered in the name of the Treasury and an easement agreement is granted to the applicant.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Please see question 6.6 below.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

With respect to natural gas, the network and distribution system is regulated by the Network Code.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

BOTAŞ has long held a monopoly role in Turkey and it was not until 2007 that a party besides BOTAŞ could access the BOTAŞ transmission network.

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The Natural Gas Market Law provides that connection and transmission tariffs are set by EMRA, rather than third parties negotiating with the company owning the transmission network (*Article 11(1) and 11(2), Natural Gas Market Law*). Third parties can apply to EMRA if a dispute arises with BOTAŞ regarding access to the transmission network (*Article 16, Transmission Network Operation Principles, published in the Official Gazette No. 25561, dated 22 August 2004*).

Parties wishing to use the BOTAŞ transmission network must first apply for a capacity allocation at an entry and exit point. Entities wishing to transport gas through a transmission or distribution pipeline owned by another licensee must enter a standard transportation contract with the licensee (*Transmission Network Operation Regulation, published in the Official Gazette No. 24918, 26 October 2002; BOTAS Transmission Network Operation Principles, published in the Official Gazette, 1 September 2004*).

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

A standard transportation contract needs to be entered into with BOTAŞ.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

With respect to transmission, the transmission network is owned and operated by BOTAŞ.

With respect to distribution, tenders are launched either by the relevant municipalities or by the Privatization Administration in respect of each province. Currently, 76 provinces in the country out of a total of 81 have access to natural gas. Currently, all distribution activities are carried out by privately held companies.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Please see question 7.1 above.

7.3 How is access to the natural gas distribution network organised?

Access to the natural gas distribution network is organised by the Natural Gas Distribution and Customer Relations Regulations.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

Urban development must be considered when expanding the system to accommodate new customers. EMRA may intervene to enforce expansion requirements.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Connection fees must not exceed 514 Turkish Liras ("**TRL**") (approximately EUR 114). A security deposit is charged, equal to TRL 406 (approximately EUR 90). Such fees are regulated in the sense that the regulator announces applicable maximum fees on a yearly basis. Fees mentioned herein are the fees applicable for 2018.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Yes, transfer of shares of a distribution company which exceeds 10% of the share capital of such distribution company needs to be approved by EMRA.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Natural gas trading is regulated under the Natural Gas Market Licensing Regulation. In order to trade natural gas in gaseous and liquid form, a wholesale licence is required from EMRA; a compressed natural gas licence is needed from EMRA for trading compressed natural gas.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas can be traded in gaseous, liquid and compressed form.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

LNG import has been regulated as a market activity by the Natural Gas Market License Regulation and Natural Gas Market Law. Accordingly, the import, storage and trade of LNG is subject to specific licences and permits. Pursuant to the Natural Gas Market Law, these market activities may be done by private sector companies within the scope of opening the natural gas market to competition. Licence application processes have been set forth by the Natural Gas Market Licence Regulation.

Turkey imports LNG based on long-term contracts from Nigeria and Algeria, and mainly on an on-the-spot basis from Qatar. According to the statistics of EMRA, 7.627 sm^3 of LNG have been imported in 2016, which corresponds to 16% of the total natural gas imports of Turkey. Despite the fact that the natural gas market has been opened to competition, LNG import activities have been done by BOTAŞ to a large extent.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

A storage licence is required to be obtained from EMRA. In addition, the following authorisations are required:

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- An EIA report.
- An environmental permit.
- A workplace and operating licence.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The prices and terms of service in the LNG sector are regulated by the guidelines of BOTAŞ and Ege Gas LNG Terminals.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

As per the guidelines, a third party can be granted co-usage rights. A third party wishing to have co-usage rights must enter into a standard form terminal utilisation service agreement with BOTAŞ and Ege Gas LNG Terminals describing the services required.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Downstream activities are regulated by the Petroleum Market Law.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Distributors/oil companies must obtain distributorship licences, whereas dealers must obtain dealership licences from EMRA, in order to conduct their business.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The Turkish Competition Authority plays an important role in ensuring the oil and natural gas sectors are competitive. EMRA, however, also regulates competition aspects in the oil and natural gas sector.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Competition law prohibits concerted practices and abuse of dominant position.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

Competition law prohibits concerted practices and abuse of dominant position. Those who are decided to have infringed the law are asked to submit their second defence in writing to the Competition Board within 30 days. Upon receiving the defence arguments, the Board experts authorised to carry out the investigation submit their additional views in writing within 15 days and this must also be notified to all the Board members and parties concerned. The parties may reply to these views within 30 days. In cases where the parties have justified reasons, this time period may be extended only once for another 30 days.

Reply of the parties not made within the specified time period is not taken into consideration.

A hearing is held if the parties concerned have requested so in their defence or reply petitions. On the other hand, the Board may also decide on a hearing on its own initiative. The hearing is held within at least 30 days and no longer than 60 days after the end of the investigation stage. The invitations for the hearing are sent to the related parties within at least 30 days before the date of the hearing.

Hearings are held in public. However, the Board may, on the grounds of protection of public morality or of trade secrets, decide to run closed sessions. Despite the possibility for closed sessions, experience shows that for the Board to decide to run a closed session, the parties have to submit strong arguments for such.

Hearings are presided over by the Chairman and in his absence by the Deputy Chairman. A hearing can only be held with the attendance of the Chairman or the Deputy Chairman and at least seven members of the Board. Hearings are to be concluded within no longer than five consequent sessions (several meetings held on the same day shall be considered as one session).

The final decision of the Competition Board is made on the same date and, if this is not possible, together with its reasoning within 15 days following the hearing.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

As per the *communiqué* of the Turkish Competition Authority that was published in the Official Gazette on 29 December 2012 and entered into force on 1 February 2013 governing the review process of the merger and acquisition transactions that are subject to the authorisation of the Turkish Competition Board, the thresholds that set the boundaries of notification requirements are as follows: (a) total turnovers of the transaction parties in Turkey exceed TRL 100 million (approximately EUR 22 million), and turnovers of at least two of the transaction parties in Turkey each exceed TRL 30 million (approximately EUR 6.7 million); or (b) in acquisition transactions, the asset or the operation that is subject to the acquisition and in merger transactions, at least one of the transaction parties has a turnover in Turkey exceeding TRL 30 million, and a global turnover of at least one of the remaining transaction parties exceeds TRL 500 million (approximately EUR 111 million).

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

The Petroleum Law, which governs the production of natural

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gas, expressly permits foreign companies to apply for upstream activities, provided that they secure a local presence in Turkey.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

With respect to downstream activities, regardless of the origin of its shareholders, any company established in Turkey is eligible to be engaged in such activities. The oil and natural gas sector is fairly influenced by international treaties. Turkey is a party to several international treaties.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

EMRA is the authority responsible for resolving disputes between licence holders. Any administrative act is subject to judicial review in Turkey, including decisions as well as administrative fines. Once they have been notified of the decision, parties with a legitimate interest are allowed 60 days to apply to the authorised administrative court.

Actions against decisions made by MENR which affect the rights arising from research permits, exploration licences, or operation licences must be filed before the Council of State as the first instance court.

For administrative acts of EMRA, parties with a legitimate interest can file a suit before the administrative courts within 60 days following the notification.

According to Article 45 of the Administrative Procedures Law, the final judgments of administrative courts may be appealed before District Administrative Courts within 30 days of the notification date. However, judgments in lawsuits where the subject matter does not exceed TRL 5,000 are considered definitive and cannot be appealed under any circumstances.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Yes, Turkey is a signatory to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the Convention on the Settlement of Investment Disputes between States and Nationals of Other States.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

No. The Administrative Procedural Law sets forth the rules as to the lawsuits which may be filed against governmental authorities and/or State organs.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

There are no reported cases in Turkey.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Increase in Exploration and Production Activities

2017 has marked a significant increase in exploration and production activities of oil and gas resources. The Ministry of Energy has announced that 44 exploration drilling points have been made in 2017, with the aim of increasing such number to 65 points. In parallel, exploration activities are also ongoing in the Mediterranean and Black Sea, including through exploration vessels recently purchased by the State-owned TPAO.

Diversification of Sources and Increase of Storage Capacities

In line with the aim of meeting the increasing demand of natural gas, the Ministry of Energy is working on several aspects in order to increase the foreseeability of the domestic energy market. Within such framework:

- Turkey has signed a three-year contract for the purchase of LNG from Qatargas in 2017. According to such purchase contract, Turkey will acquire 1.5 million tons of LNG from Qatar on an annual basis for a total period of three years.
- The Ministry of Energy has announced two floating LNG storage and re-gasification units to be located in Hatay (southeast of Turkey) and Saros bay (northwest of Turkey).

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The energy industry is a complex and highly competitive sector. It is obvious that there is a need for professional advisers who understand the business of companies active in this sector, and who have the experience and capacity to handle complex international energy projects.

Schoenherr can assist you with a multi-disciplinary group of lawyers drawn from across the firm's broad international network that specialise in the specifics of the energy sector. The energy group comprises of lawyers from all practice areas with a detailed understanding of the energy sector and of the needs of international energy clients. Sharing our knowledge and co-operating tightly between our practice groups and between our international offices, our energy group can help you to respond to the changes in the industry and to keep pace with market and regulatory developments.

Our lawyers are regularly involved in both international and domestic energy matters including transactions, development projects, mergers and acquisitions, privatisations, public-private partnerships, regulatory matters, public procurement, strategic advice, competition matters and dispute resolution.

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Chapter 26

United Arab Emirates

Dentons

Mhairi Main Garcia

1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

The United Arab Emirates (the "UAE") was established in 1971 as a federation of emirates. There are seven emirates, each with its own Ruler: Abu Dhabi; Ajman; Dubai; Fujairah; Ras Al Khaimah (which joined the federation in 1972); Sharjah; and Umm Al Quwain. The Emirate of Abu Dhabi, which holds the majority of the UAE's hydrocarbon resources, is the capital of the UAE.

The oil and gas sector accounts for more than one-third of the UAE's gross domestic product. Natural gas plays a key role in the UAE's energy mix. The UAE has the seventh largest proven natural gas reserves in the world (after Iran, Russia, Qatar, Turkmenistan, the United States and Saudi Arabia). The UAE's proven natural gas reserves at the end of 2016 stood at 6.1 trillion cubic metres, representing approximately 3.3 per cent of the world's total proven reserves. The Emirate of Abu Dhabi holds more than 94 per cent of these reserves, where the non-associated Khuff natural gas reservoirs beneath the Umm Shaif and Abu Al Bukhoosh oil fields are amongst the largest in the world. The Emirates of Sharjah and Dubai hold approximately 4 per cent and 1.5 per cent of the UAE's reserves respectively; however, the gas fields in these emirates have matured and their production rates have fallen in recent years. Natural gas production in the UAE increased during 2016, by 2.5 per cent compared with 2015. The UAE produced 61.9 billion cubic metres of marketed natural gas in 2016, representing 1.7 per cent of global marketed natural gas production for that year.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Natural gas accounts for the majority of the UAE's total energy consumption (representing 61 per cent of consumption during 2016), followed by crude oil (just over 38 per cent in 2016), with coal making up the remainder. Consumption of natural gas increased during 2016 by 3.6 per cent compared with 2015. In 2016, the UAE consumed 76.6 billion cubic metres of natural gas, amounting to 2.2 per cent of total world consumption. Increased electricity consumption (accompanied by a preference for natural gas as the feedstock for power generation and water desalination plants) and a growing petrochemicals industry continue to contribute to the increase in demand; it is estimated that approximately half of the UAE's natural gas production is used for domestic power generation during the peak summer months. Significant quantities of natural gas are also used in re-injection operations for oil reservoir pressure maintenance.

Domestic gas consumption in the UAE exceeds production. Most of the UAE's natural gas production is associated gas or sour gas in non-associated fields. Production in the associated fields is limited by the UAE's OPEC quotas, since the associated gas production is determined by oil output.

The UAE has embarked on a substantial investment programme to boost domestic gas production, most notably the sour gas development projects in Abu Dhabi. ADNOC Sour Gas (previously known as Abu Dhabi Gas Development Company Limited, Al Hosn Gas) was established in 2010 to manage, operate and develop the Shah Gas Field Project. The company is owned by Abu Dhabi National Oil Company ("ADNOC") and Occidental Petroleum (with ADNOC holding a 60 per cent majority share).

The Shah Gas Field Project began gas production in January 2015 and involves the development of high sulphur content reservoirs within the Shah Gas Field, located onshore, south-west of the city of Abu Dhabi. It comprises the development of several gas gathering systems and the construction of gas and liquid pipelines and processing trains to process high sulphur content gas. Gas, condensate and natural gas liquids are transported to other processing and distribution facilities at Habshan for use as feedstock for gas-fired power and desalination plants, industrial development and oil field pressure maintenance re-injection operations.

In addition, as a means of addressing the shortfall in domestic gas supply, the UAE is assessing alternative energy sources, including nuclear energy and renewables. The world's largest single nuclear project, Abu Dhabi's Barakah nuclear project, will have capacity of 5,600MW; the first of four 1,400MW reactors is scheduled to be operational during 2018.

Dubai and Abu Dhabi have also pursued ambitious solar energy projects as part of their energy diversification, with large utility scale solar photovoltaic ("PV") and concentrated solar power ("CSP") projects. In 2014, Phase II of Dubai's Mohammed Bin Rashid Al Maktoum Solar Park was tendered as a 100MW solar PV power project; the project achieved a record-breaking tariff in the absence of subsidies and doubled its size to 200MW. Phase III followed in 2016, a massive 800MW of PV and another record-

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breaking tariff; this was followed in 2017 by Phase IV, a 700MW CSP project, the largest single-site CSP project in the world. In Abu Dhabi, the Sweihan solar PV power project, which was tendered in 2016, also achieved a record tariff and the project is being upsized from the initial 350MW to a colossal 1,177MW.

Coal is also joining the UAE's energy mix. Dubai is developing a clean coal-fired power complex at Hassyan, the first phase of which is a USD2.47 billion project with a capacity of 2,400MW. Further north, the Federal Electricity and Water Authority has asked for expressions of interest in a 1,800MW coal-fired power project, to be built in the Emirate of Ras Al Khaimah.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

The UAE's natural gas requirements are met through domestic production and imports from Qatar. In 2016, the UAE imported 17.9 billion cubic metres of natural gas from Qatar through the Dolphin Gas Project's export pipeline. The UAE also exports a large amount of gas, notwithstanding its reliance on imports to meet the UAE's domestic needs.

The Dolphin Gas Project involves the production of natural gas from Qatar's North Field, the processing of the natural gas at Ras Laffan Industrial City and the transportation of the dry gas by a sub-sea export pipeline from Qatar to gas-receiving facilities at Taweelah in Abu Dhabi. The export pipeline has been operational since July 2007. It has a design capacity of approximately 35 billion cubic metres *per annum*, and its initial contracted capacity is 22 billion cubic metres *per annum*.

The Dolphin Gas Project is owned by Dolphin Energy, in which Abu Dhabi Government-owned Mubadala Investment Company holds a 51 per cent interest, with Total and Occidental Petroleum each holding a 24.5 per cent interest. Dolphin Energy has signed long-term gas supply contracts with the Abu Dhabi Water and Electricity Company ("ADWEC"), the Dubai Supply Authority ("DUSUP"), Sharjah Electricity and Water Authority, RAK Gas and Oman Oil Company.

DUSUP's floating LNG regasification facility in Dubai supplements existing supplies of natural gas during summer peak demand. A floating storage and regasification unit ("FSRU"), chartered by DUSUP from Golar LNG, is moored offshore within the Jebel Ali terminal. Also, in 2016, Abu Dhabi chartered an FSRU from Excelerate. The FSRU is moored at Ruwais and is the first facility to allow Abu Dhabi to import LNG to meet growing and immediate domestic gas demand.

Natural gas may also be imported into the UAE from Iran in the future. While a number of Iranian pipeline gas import proposals have been considered, the most developed is Crescent Petroleum's project with the National Iranian Oil Company to import natural gas by pipeline from Iran's Salman field into Sharjah. However, although Crescent Petroleum and the National Iranian Oil Company agreed a 25-year contract in 2001 and much of the pipeline and associated project infrastructure has already been built, the project has been the subject of protracted litigation. Nonetheless, in 2017, public reports indicate that both sides are now showing a readiness to reignite the project and for Iranian gas to be received through the Crescent Petroleum infrastructure.

The Sharjah Western Offshore Concession is located off the Sharjah coastline and includes the Zora Gas Field, which straddles Sharjah and Ajman and is being developed by Dana Gas. Gas from the Zora Gas Field is being piped to an onshore gas processing facility in Sharjah's Hamriyah free zone. In 2017, Sharjah Petroleum Council signed a 23-year concession agreement with Rex Oil and Gas Limited for oil and gas exploration and drilling in Sharjah's Eastern offshore concession (at Khorfakkan and Kalba).

Dana Gas is also developing the UAE Gas Project, which will receive gas at a Dana Gas-owned receiving platform offshore Sharjah and will then transport the gas by an 80-kilometre onshore and offshore pipeline, to the gas processing facilities in Sharjah, which are operated by SajGas (also owned by Dana Gas). The gas will be sweetened and processed to produce gas for sale in the UAE along with natural gas liquids. Due to ongoing delays in commissioning of the gas supplier's facilities, deliveries of gas have yet to commence.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

During 2016, the UAE exported 7.4 billion cubic metres of LNG, including 6.5 billion cubic metres to Japan and 0.7 billion cubic metres to India.

There are no pipeline exports of UAE domestic gas production. The Dolphin Gas Project does, however, involve the transportation of natural gas from Qatar to Oman through pipeline infrastructure located within the UAE.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

The UAE has the eighth largest proven crude oil reserves in the world (after Venezuela, Canada, Saudi Arabia, Iran, Iraq, the Russian Federation and Kuwait). The UAE's proven crude oil reserves at the end of 2016 remained unchanged (in comparison to 2015) at 97.8 billion barrels, representing approximately 5.7 per cent of the world's total proven reserves. The Emirate of Abu Dhabi holds approximately 94 per cent of these reserves.

The UAE is a member of the Organisation of the Petroleum Exporting Countries ("OPEC"). The UAE's production targets are set by OPEC. The UAE's average daily crude oil production in 2016 remained stable at almost 3.088 million barrels. In 2016, there were 1,835 producing wells in the UAE (up 43 as compared with 2015); 52 wells were completed in 2016. There were 79 active rigs in 2016 (up by 28 compared with 2015).

Oil production is dominated by a handful of large fields, most of which were discovered in the 1960s and 1970s and which have been producing for several decades. These fields include the Bu Hasa, Upper Zakum, Bab, Lower Zakum, Asab and Umm Shaif fields, all located in Abu Dhabi. The likelihood of further major discoveries in the UAE is relatively low; however, enhanced oil recovery techniques are being successfully utilised to increase the extraction rates of mature oil fields.

In the Emirate of Abu Dhabi, the Supreme Petroleum Council has overall policy-making responsibility for the petroleum industry, as well as management control over the Abu Dhabi Government-owned oil company, ADNOC. ADNOC is responsible for managing day-to-day operations and implementing the directives of the Supreme Petroleum Council. ADNOC's subsidiary companies work in the fields of exploration and production, support services, oil refining and gas processing, chemicals and petrochemicals, maritime transportation and refined products and distribution.

Production in the UAE is dominated by ADNOC Onshore and ADNOC Offshore. ADNOC Onshore (previously known as Abu Dhabi Company for Onshore Oil Operations, ADCO) operates the onshore concession originally granted in the 1930s. ADNOC Offshore, which has been formed through the consolidation of the

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Abu Dhabi Marine Operating Company ("ADMA-OPCO") and Zakum Development Company ("ZADCO") operates the offshore concessions. ADMA-OPCO operates the offshore concession originally granted in the 1950s and ZADCO operates the Upper Zakum offshore field and the Umm Al-Dalkh and Satah offshore fields. In 1974, the equity interests of the original concession holders were diluted and ADNOC was granted a majority interest.

Opportunities for exploration and production in the UAE have been relatively limited and historically there was a narrow pool of participants. In 2008, Occidental Petroleum was awarded a concession covering two onshore fields in Abu Dhabi, and ConocoPhillips was awarded a contract to develop the Shah Gas Field (ConocoPhillips later withdrew and was replaced by Occidental Petroleum in 2011). In 2012, Korea National Oil Corporation and GS Energy were awarded a concession covering two onshore areas and one offshore area in Abu Dhabi. Also in 2012, OMV and Wintershall signed a technical evaluation agreement with ADNOC to appraise the Shuweihat sour gas and condensate field. This agreement is significant in that it represents a departure from the historically favoured concession agreement.

ADNOC Onshore's oil and gas output accounts for more than half of the UAE's total production. The ADNOC Onshore concession expired at the start of 2014 and a new 40-year concession has been awarded. ADNOC Onshore remains majority owned by ADNOC (which holds a 60 per cent interest); the remaining interests are now held by BP (10 per cent), Total (10 per cent), China National Petroleum Company (8 per cent), Japan Oil Development Co., Ltd. ("JODCO"), a wholly owned subsidiary of Inpex (5 per cent), China Energy Company Limited (4 per cent) and GS Energy Corporation (3 per cent). The concession area continues to cover the integrated asset groups of Bab, Bu Hasa, South East (Sahil, Asab, Shah, Qusahwira, Mender) and Northeast Bab (Al Dabb'iya, Rumaitha, Shanayel).

The offshore concession operated by ADMA-OPCO, which comprises the fields of Lower Zakum, Umm Shaif, Nasr, Umm Lulu and Satah Al Razboot (Sarb), is due to expire in March 2018. The ADMA-OPCO concession is currently majority owned by ADNOC (which holds a 60 per cent interest); the remaining interests are held by BP (14.67 per cent), JODCO (12 per cent) and Total (13.33 per cent). ADNOC has confirmed that the concession will be split into two or more concessions; ADNOC will retain its 60 per cent interest in each concession. At the time of writing, although ADNOC has been in discussions and signed framework agreements regarding possible participation in the new concessions, there has been no decision on which entities will be awarded the concessions and their participating interests.

The offshore concession operated by ZADCO was due to expire at the end of 2041; however, it was announced in November 2017 that this concession has been extended by a decade to 2051. As with the other concessions, it is majority owned by ADNOC (which holds a 60 per cent interest); the remaining interests are held by ExxonMobil (28 per cent) and JODCO (12 per cent). Going forward, the new ADMA-OPCO concessions and the existing concession operated by ZADCO will be operated by the combined ADNOC Offshore.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Natural gas accounts for the majority of the UAE's total energy consumption (representing 61 per cent of consumption during 2016), followed by crude oil (just over 38 per cent in 2016), with coal making up the remainder.

The UAE has one of the world's highest rates of per capita oil consumption. In 2016, the UAE consumed 987,000 barrels of oil per day, amounting to 1 per cent of total world consumption. This represented an increase of 6.7 per cent as compared with 2015. In 2016, the UAE's oil consumption by main petroleum products was as follows: 176,000 barrels of gasoline per day; 148,000 barrels of kerosene per day; 106,000 barrels of distillates per day; 329,200 barrels of residuals per day; and 40,000 barrels of other petroleum products per day.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

The UAE's oil requirements are met almost entirely through domestic production.

2.4 To what extent is your jurisdiction's oil production exported?

In 2016, the UAE exported just under 2.5 million barrels of crude oil per day. Of those export quantities, 18,400 barrels per day were exported to Europe, 6,600 barrels per day were exported to North America, 2.36 million barrels per day were exported to countries in the Asia Pacific region, 20,500 barrels per day were exported to Africa and 1,300 barrels per day were exported to other Middle East countries.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Each emirate of the UAE has constitutionally entrenched rights to the natural resources (including oil and natural gas) within that emirate; such resources are deemed the public property of that emirate. As a result, each emirate pursues its own policies regarding the development of oil and natural gas, with the Ruler in each emirate retaining ultimate control over the development of oil and natural gas reserves in that emirate.

The right to explore, develop and produce petroleum is typically granted by way of a concession by the applicable emirate. Concessions are usually granted to state-controlled companies, with participation by international oil companies being limited to minority ownership interests in the project companies which are granted the concessions and the provision of technical services to those project companies.

Abu Dhabi does not have comprehensive petroleum legislation governing the granting of exploration and development concession rights; however, a number of laws affect the petroleum industry, including the Abu Dhabi Gas Ownership Law (Abu Dhabi Law No. 4 of 1976), the Abu Dhabi Petroleum Resources Conservation Law (Abu Dhabi Law No. 8 of 1978), the Abu Dhabi Petroleum Ports Law (Abu Dhabi Law No. 12 of 1973, as amended) and the Abu Dhabi Tax Decree of 1965 (as amended). The Supreme Petroleum Council, which was established in 1988, regulates Abu Dhabi's oil and natural gas policy.

Under the Abu Dhabi Gas Ownership Law, all natural gas discovered or to be discovered in the territorial zone of the Emirate of Abu Dhabi is the sole property of the Emirate of Abu Dhabi. The Emirate of

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Abu Dhabi maintains rights over gas at the delivery points and in all stages of production. Since 1976, the ADNOC group of companies has managed upstream, midstream and downstream oil and gas operations on behalf of the Government of Abu Dhabi: article 4 of the Abu Dhabi Gas Ownership Law affords ADNOC the right to exploit and use all gas discovered or to be discovered within Abu Dhabi and to claim all rights derived from agreements concluded by the Government of Abu Dhabi which are related to gas discovered or produced or the facilities of production and extraction of gas. As previously mentioned, ADNOC is owned by the Abu Dhabi Government and the management of ADNOC reports directly to the Supreme Petroleum Council.

In Sharjah, the Sharjah Petroleum Council is responsible for regulating policy regarding the development of oil and natural gas in that emirate. The Sharjah Petroleum Council is responsible for submitting recommendations to the Ruler for concessions and concluding such agreements. It is also the body that represents the Sharjah Government in companies in which it participates in the field of oil and gas investments.

In Dubai, operations are carried out through concessions or contracts concluded between companies and the Government of Dubai. The Department of Oil Affairs is responsible for approving licences necessary to perform oil-related activities. In addition, the Dubai Supreme Council of Energy is responsible for providing primary energy resources (defined to include crude oil and natural gas) at a reasonable cost and reducing the negative environmental impacts arising therefrom. The Supreme Council of Energy is also responsible for promoting the cost-effectiveness and quality of services rendered for energy supply by all available means, including using incentives and imposing tariffs.

The Federal Ministry of Energy has limited powers to set policies and planning at a federal level and is subject to the constitutional rights of the emirates. Approvals are also required from the Federal Ministry of Environment and Water in accordance with the UAE Law on the Protection and Development of the Environment (Federal Law No. 24 of 1999) (the "Federal Environment Law"). In practice, federal approvals are overseen by the Ministry of Environment and Water, but it is the local emirate environmental departments that are responsible for approvals in that emirate and enforcing the requirements of the Federal Environment Law, as well as the applicable local environmental regulations and laws.

Regionally, the states of the Gulf Co-operation Council ("GCC") (the six GCC members are the Kingdom of Bahrain, the Kingdom of Saudi Arabia, the State of Kuwait, Qatar, the Sultanate of Oman and the UAE) have agreed to pursue unified policies in the exploitation of natural resources. The GCC Economic Agreement (incorporated into UAE domestic law by Federal Decree No. 55 of 2002) provides that the GCC states will adopt integrated policies in all stages of the oil and gas industries in a manner that facilitates the best exploitation of natural resources, taking into account environmental considerations and the interests of future generations, and that they will implement unified policies for oil and gas, adopting a common position towards non-Member States and international organisations.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

The granting of oil and natural gas development rights is overseen by the respective regulatory bodies in each emirate. Foreign companies or investors are generally not permitted to hold majority interests in oil or natural gas development activities or enterprises. In the majority of circumstances, the right to explore, develop and produce oil and natural gas is granted by way of a concession by the applicable emirate. Concessions are usually granted to state-controlled companies, with the involvement of international oil companies being limited to minority ownership interests in the concession project company.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The concessions typically embody the principal authorisations necessary for the exploration, development and production of oil and natural gas. Concession terms vary, both between the different emirates and within the emirates themselves, depending on a number of factors, including the date of the initial grant, the size and importance of the development and the level of foreign involvement.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Each emirate participates directly in the development of oil and natural gas. In most circumstances, concessions are granted by the emirate to the state-owned petroleum company, or to a concession project company in which the emirate or the state-owned petroleum company will hold, directly or indirectly, a majority interest. Given that the majority of the oil and natural gas reserves in the UAE are located in Abu Dhabi, most oil and natural gas development and production activities are carried out by companies within the ADNOC group of companies. Under article 6 of the Abu Dhabi Gas Ownership Law, ADNOC has the right to exploit natural gas in Abu Dhabi alone or in joint ventures with third parties, provided that ADNOC's share does not fall below 51 per cent.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

At emirate level, the emirates derive value from oil and natural gas development through equity participation (discussed above) and taxation. The taxation of oil and natural gas development activities is regulated by the individual emirates. The taxation of companies engaged in oil and gas activities is one of the limited cases of corporate tax being levied in the UAE.

In Abu Dhabi, a corporate tax applies to oil and natural gas activities in accordance with the Abu Dhabi Income Tax Decree of 1965 (as amended). Although not a petroleum-specific decree, in practice it applies only to "chargeable persons" which are "dealing in oil", as well as "chargeable persons" defined to include foreign entities, ADNOC and its subsidiaries, and any other domestic companies that are "dealing in" petroleum. The tax rate ranges between 55 and 85 per cent depending on the product that generates the taxable income. The Supreme Petroleum Council grants tax incentives to businesses that benefit Abu Dhabi in terms of, for example, economic development, investment, technology transfer and training of UAE nationals. The tax incentives may include tax holidays and reduced tax rates.

At a federal level, the majority of the Federal Government's income is contributed by Abu Dhabi. The other emirates do not contribute to the federal budget and are, to varying degrees, dependent on federal expenditure for their development and infrastructure.

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3.6 Are there any restrictions on the export of production?

There are currently no restrictions on the export of production, although standard export controls (through permits) apply on certain products for safety, security and environmental reasons, and to ensure compliance with international obligations under treaties and conventions to which the UAE is a party. The UAE also restricts exports of dual-use goods that may be used as weapons.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

The UAE dirham, the official currency of the UAE, is pegged to the US dollar. The exchange system is generally free of restrictions on international payments and transfers. However, there are certain restrictions under terrorist financing provisions that have been implemented in accordance with the UAE's international obligations, and in relation to Israeli currency. Under Federal Law No. 4 of 2002 (as amended), the UAE introduced anti-money laundering legislation, imposing documentary requirements on large wire transfers and the import of large currency amounts. All suspicious transactions must be reported to the Financial Intelligence Unit within the UAE Central Bank.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

In accordance with the terms of the individual concession, the approval of the relevant emirate is required prior to the transfer of oil and natural gas concession rights.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Participants are generally not obliged to provide any security or guarantees in connection with the granting of oil and natural gas development rights.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Equity participation under the concession would ordinarily facilitate the booking of reserves and, subject to the terms of the relevant concession, such rights may be pledged for security.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Authorisations are required at both federal level and emirate level. Participants are obliged to comply with the framework of federal and local environmental, health and safety laws and regulations. Environmental protection is regulated at a federal level by the Ministry of Environment and Water in accordance with the Federal Environment Law. Amongst other things, the Federal Environment Law requires permits to be issued and environmental impact assessments to be undertaken in respect of oil and natural gas development projects. The Federal Environment Law also regulates the disposal of waste and hazardous materials, which can potentially impact upon oil and natural gas development operations.

Under the Federal Environment Law, parties licensed to prospect, extract or exploit onshore or offshore oil and gas fields are prohibited from discharging any polluting substance resulting from drilling, exploring, testing of wells or production into the water or land area in the vicinity of those activities, unless safety measures are adopted. Such safety measures must safeguard against harm to land and water environments, and oblige the parties to treat discharged waste and polluting substances in accordance with technical systems approved under regional and international conventions and protocols. Emissions from the burning of fuels or other substances for any commercial purpose must be within the permissible limits and the amounts of pollutants in combustion emissions must be recorded. There are also specific requirements for the transportation by sea of hazardous substances. A local authority in each of the emirates is the competent authority responsible for implementing the Federal Environment Law.

In addition, there are a number of laws, regulations and guidelines in place at emirate level that address environmental concerns, including regulations on storage, transportation of hazardous substances, waste management and record-keeping. In relation to health and safety, a number of safety regulations have been introduced by the Federal Ministry of Human Resources and Emiratisation, local authorities and the Civil Defence (i.e. the fire service).

All large industrial enterprises are required to have in place certified occupational safety officers. Health and safety issues are becoming increasingly important in the UAE oil and gas sector, with most companies implementing health and safety measures in line with international practice.

ADNOC acts as the environmental regulator of the Abu Dhabi oil and gas industry. ADNOC proactively regulates its group companies and pursues a number of strategic objectives for health, safety and the environment, which are subject to implementation by its subsidiaries including ADNOC Gas Processing, ADNOC LNG, ADNOC Onshore, ADNOC Offshore and ADNOC Refining. ADNOC operates codes of practice and a health, safety and environment management system requiring its group companies to develop and implement compatible programmes.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

There are only limited laws and regulations that relate to abandonment and decommissioning. In Abu Dhabi, participants must comply with the general requirements relating to pollution and protection of the environment, which fall under a combination of the Federal Environment Law, the Abu Dhabi Petroleum Resources Conservation Law (Law No. 8 of 1978), the Abu Dhabi HSE Decree, consents required by the Supreme Petroleum Council, the environmental regulations and codes of practice implemented by ADNOC and the terms of the applicable concession.

The Abu Dhabi Petroleum Resources Conservation Law includes limited obligations in relation to abandonment and decommissioning. These obligations appear primarily related to ensuring that the petroleum resources have been used to their full potential prior to abandonment or decommissioning, rather than setting in place financial obligations and/or security for decommissioning. Consent of the Supreme Petroleum Council is required to suspend or abandon

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a producing project, which is subject to the operator specifying the reasons for suspension or abandonment and the results achieved until the date of the suspension or abandonment request.

The UAE is a party to the Kuwait Protocol, pursuant to which the operator of an offshore installation in the case of platforms and other sea-bed apparatus and structures should be required to remove the installation in whole or in part to ensure safety of navigation and the interests of fishing. Each contracting state must also take practical measures to ensure that the operator has sufficient resources to guarantee that any such requirements can be met. Accordingly, pursuant to the Kuwait Protocol, the UAE is obliged to ensure that offshore participants have adequate resources in place to deal with abandonment and decommissioning.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/ requirements of the legislation?

There are a number of health, safety and environmental regulations that set out the specifications for gas storage. The regulations differ from emirate to emirate and, within the emirates, certain free zones impose standards, regulating, amongst other things, temperature and pressure requirements. Civil Defence requirements must also be complied with. In addition to the approval of the relevant emirate, approvals may be required pursuant to the Federal Environment Law.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

There are no express regulatory requirements that apply in respect of cross-border sales or deliveries of natural gas. In terms of exports, standard export controls may apply (see above for further details).

The emirates each have their own local customs departments, which fall under the Federal Customs Authority. The role of the Federal Customs Authority is to unify, develop and improve customs policies, legislation and regulations, and supervise their implementation across the local customs departments. The customs procedures are similar throughout the UAE.

Since the establishment of the GCC customs union on 1 January 2003, the UAE has applied the GCC Common Customs Law, which provides for a single port of entry whereby items imported into the UAE (or any other GCC state) that are destined for another GCC market are subject to customs duty only at the first point of entry into the GCC. Customs procedures and the required documentation are the same for all GCC states.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

There are no express regulatory requirements that apply in respect of cross-border sales or deliveries of oil and oil products. In terms of exports, standard export controls may apply (see above for further details).

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Each emirate controls its own infrastructure for the transportation of oil and natural gas. As a result, different government bodies and authorities regulate oil and gas transportation within the different emirates, setting various standards and codes of practice. There is also regulation at a federal level by the Ministry of Petroleum and the Ministry of Environment and Water.

In Abu Dhabi, ADNOC Gas Processing (previously known as GASCO) operates gas processing plants located in the Western Region of Abu Dhabi and Ruwais, including one of the largest gas processing plants in the world. Processing gas from Abu Dhabi's onshore and offshore fields, ADNOC Gas Processing produces a range of products, including methane, ethane, propane, butane, paraffinic naphtha, condensates and sulphur. In 2017, ADNOC Gas Processing opened the USD6.85 billion Habshan 5 gas processing plant, which will produce natural gas liquids, sales gas, liquid sulphur and condensate.

ADNOC Gas Processing – through its pipelines division – manages, operates and maintains a 3,000-kilometre gas pipeline network, which supplies oil fields, power plants and petrochemical facilities, as well as customers throughout the UAE. The infrastructure, which spreads throughout Abu Dhabi, is arranged around three gas distribution manifolds at Maqta, Habshan and Bab. From these manifolds, the pipelines branch off to the industrial centres at Ruwais, Asab, Buhasa, Mirfa, Maqta, Taweelah and Al Ain.

ADNOC Refining also operates a 1,900-kilometre pipeline network across the Emirate of Abu Dhabi to deliver refined oil products to oil ports for exportation, or to other ADNOC Group companies for further processing. The Abu Dhabi crude oil pipeline, one of the newer pipelines, runs 380 kilometres and transports crude oil from the ADNOC Onshore facilities at Habshan to the export terminal in Fujairah.

The UAE imports gas from Qatar through the Dolphin Gas Project's export pipeline. The export pipeline transports refined gas from the Ras Laffan processing plant in Qatar to gas-receiving facilities at Taweelah in Abu Dhabi. From there, the majority of the gas is supplied to other parts of the UAE, using the Eastern Gas Distribution System. The Eastern Gas Distribution System is also used to transport natural gas to Oman, using a connection with an Omani pipeline on the Oman border. Dolphin Energy also owns the Al Ain to Fujairah pipeline and the Taweelah to Fujairah pipeline, both of which are connected to the Dolphin Gas Project and supply power stations and desalination plants in Fujairah.

In Abu Dhabi, the Jebel Dhana, Ruwais, Umm Al-Nar, Das Island and Zirku Island terminals handle petroleum exports. They are owned and operated by ADNOC Logistics & Services (previously known as the Abu Dhabi Petroleum Ports Operating Company, Irshad). The Jebel Ali terminal in Dubai and the Fujairah terminal in Fujairah also handle petroleum exports. The export terminal in Fujairah is one of the largest bunkering ports in the world and there are plans to expand its capabilities.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The individual emirates regulate the requirements and procedures for

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obtaining permits for transporting oil and natural gas. In addition, approvals are required at a federal level, with the Ministry of Petroleum and the Ministry of Environment and Water responsible for preparing guidelines in respect of environmental safety and management of waste resulting from the transportation of oil and gas.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Under the UAE Constitution, the natural resources in each emirate are the public property of that emirate. Further, as the Ruler of each emirate ultimately owns the land in that emirate, the construction of oil or natural gas transportation pipelines or associated infrastructure requires a grant of rights from the relevant Ruler. The Rulers also possess powers of compulsory acquisition to facilitate land access. Article 121 of the UAE Constitution permits expropriation in the public interest. In the event that foreign private property is expropriated or nationalised, a payment of compensation has to be made to the affected party.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Access to oil and natural gas transportation pipelines and associated infrastructure is organised at emirate level. The emirate granting the rights to construct, own and operate oil and natural gas transportation pipelines or associated infrastructure retains inherent rights of access on the basis that the Ruler ultimately owns the land upon which such infrastructure is located.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

There is limited integration and interconnection of oil and natural gas transportation pipelines within the UAE. Gas from the Dolphin Gas Project is transported from Qatar to the Taweelah receiving facilities in Abu Dhabi through the export pipeline. From there, the gas is fed into the Eastern Gas Distribution System, a network of recently developed or renovated pipelines. The Eastern Gas Distribution System, together with the Taweelah to Fujairah and Al Ain to Fujairah pipelines, links Taweelah (on the UAE's west coast in Abu Dhabi) to Fujairah (on the east coast of the UAE), Taweelah to Maqta, Maqta to Jebel Ali (in the Emirate of Dubai), Maqta to Al Ain, Al Ain to Fujairah, and Taweelah to Jebel Ali.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

There are no standard rights for a new customer to compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate new customers. Regulation is governed by the emirate concerned, which may include third-party access rights or rights to expand capacity/facilities as a matter of contract.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

The parties are at liberty to agree the terms upon which the oil or natural gas is to be transported.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

There is no integrated framework for the ownership, organisation and/or regulation of natural gas transmission/distribution infrastructure. Each emirate oversees the ownership, organisation and regulation of such infrastructure within its territory.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

Government authorisations to operate a distribution network are required at emirate level and at a federal level from the Ministry of Petroleum and the Ministry of Environment and Water.

7.3 How is access to the natural gas distribution network organised?

There are no specific laws organising access to the natural gas distribution network. Access is organised at emirate level and is linked to the rights granted by the relevant emirate for constructing any pipeline or associated infrastructure.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

The natural gas distribution systems are currently owned and operated by a number of parties under different operational protocols.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Fees charged for accessing the distribution network are a matter of contract between the parties.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

There are no specific restrictions or limitations in relation to acquiring an interest in a gas utility or the transfer of assets forming part of the distribution network. There is a general requirement under the Commercial Companies Law that all entities must be majority owned

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by UAE nationals or wholly owned UAE entities. However, pursuant to article 4, the Commercial Companies Law does not apply, among other things, to companies in which "the Federal Government, the Local Government or any of the establishments, authorities, departments or any companies controlled or held by any of them directly or indirectly, and having at least 25 per cent of the shares of such companies, which operate in oil exploration, drilling, refining, manufacturing, marketing and transportation or operating in the energy sector of all kinds or in… gas production", provided there is a special provision to this effect is contained in the memorandum of association or articles of association of such companies. The local licensing requirements applicable in each emirate will also have to be satisfied.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

There is no specific framework for the ownership, organisation or regulation of natural gas trading.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

There is currently no trading of natural gas commodities in the UAE.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

LNG is regulated by the respective emirates. There is no regulatory regime specific to LNG; rather LNG falls within the various energy, environmental and health and safety laws and regulations applied in each emirate.

Government participation is prevalent through ADNOC LNG (previously known as ADGAS). ADNOC LNG was the first LNG production company in the region; ADNOC holds a 70 per cent interest in the company, with Mitsui & Co holding 15 per cent, BP 10 per cent and Total 5 per cent.

ADNOC LNG operates an LNG plant on Abu Dhabi's Das Island, which has been operating since 1977. The plant receives gas streams from both associated and non-associated offshore fields.

During 2016, the UAE exported 7.4 billion cubic metres of LNG, 6.5 billion cubic metres of which was delivered to Japan under a long-term contract between ADNOC LNG and JERA Co Inc (a combination of Tokyo Electric Power Company, TEPCO, and Chubu Electric Power Group). The relationship dates back to the 1970s. In 1994 a new agreement came into effect pursuant to which JERA and ADNOC LNG agreed to double LNG cargoes for the period from 1994 to 2019. At the time of writing, it is unclear, given the reliance of the UAE on natural gas imports, the continued increase in domestic demand for natural gas and the surplus of LNG supply globally, whether this contract will be renewed when it expires in March 2019 and, if so, the terms of such renewal.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

Approvals are required from the relevant emirate and, at a federal level, from the Ministry of Environment and Water in accordance with the Federal Environment Law.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

There is no regulation of the price or terms of service in the LNG sector.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

As with natural gas in general, the regulatory regime for LNG is within the jurisdiction of the individual emirate and is addressed on an *ad hoc* basis with no LNG-specific laws. There are no standard rights for third-party access in respect of LNG facilities; third-party access or third-party rights may be granted as a matter of contract.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

There is no regulatory regime specific to the downstream oil sector; rather downstream oil falls within the various energy, environmental and health and safety laws and regulations applied in each emirate.

In Abu Dhabi, government participation in the downstream oil sector is prevalent through ADNOC Refining (previously known as Abu Dhabi Oil Refining Company, Takreer). ADNOC Refining was established in 1999 and is responsible for all refining operations, including refining crude oil and condensate, supplying petroleum products in compliance with domestic and international standards, and producing sulphur granulation.

The UAE had refinery capacity of 710,000 barrels per day in 2013; by 2014, this capacity increased by over 60 per cent to over 1.143 million barrels per day, representing 1.2 per cent of the world total. This capacity has subsequently remained stable. The increase in capacity was achieved by more than doubling the capacity of the Ruwais refinery, making it one of the largest refineries in the world. ADNOC Refining is expected to tender a contract in 2018 for a gasoline and aromatics project at the Ruwais refinery.

In 2017, Abu Dhabi's petroleum and petrochemicals company, Mubadala Investment Company (created by a merger between International Petroleum Investment Company, IPIC, and Mubadala Development Company), confirmed that a 200,000 barrels per day refinery will be built at the port of Fujairah. The project had previously been abandoned; however, the merger, coupled with a fire at the major Ruwais refinery at the beginning of 2017, as well as regional political developments, has led to a commitment to kick-start this project. It is also hoped that this project will help promote Fujairah, located on the east coast of the UAE and one of the largest bunkering ports in the world, as a petroleum trading hub for the Middle East and Asia.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The UAE has local markets trading in crude oil futures and fuel

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oil futures. The Dubai Mercantile Exchange ("DME") operates as the primary international energy futures and commodities exchange in the Middle East. The DME trades the DME Oman Crude Oil Futures Contract, the sole benchmark for Oman and Dubai crude oil Official Selling Prices, which historically established markers for Middle Eastern crude oil exports to Asia.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

As a result of the high level of state participation, there is no effective competition in the oil and natural gas sector.

UAE Federal Law No. 4 of 2012 on the regulation of competition (the "Competition Law") entered into force in February 2013. The Competition Law regulates restrictive agreements, abuse of market power and merger control. Under the Competition Law, agreements or practices that are regulated are exempt from the law unless the Ministry of Economy agrees to review a matter following a request from another regulatory authority. As a result, activities and services that are regulated by the relevant emirate's petroleum regulator will ordinarily be exempt from the Competition Law. Moreover, services and activities in the oil and gas sectors are specifically exempted.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

See above: oil and gas activities are exempted from the Competition Law.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

See above: oil and gas activities are exempted from the Competition Law.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

See above: oil and gas activities are exempted from the Competition Law. Any mergers or changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of oil and natural gas development assets, transportation pipelines or associated infrastructure, require the approval and consent of the relevant emirate and are subject to any change of control provisions in the relevant concession. There are no standard criteria or procedures that apply in respect of such transactions.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There is a general requirement under the Commercial Companies Law (Federal Law No. 2 of 2015) that all entities must be majority owned by UAE nationals or wholly owned UAE entities. However, as stated above, the Commercial Companies Law does not apply to companies which carry on the activities of oil exploration, drilling, refining, manufacturing, marketing, transportation and gas production and in which "the Federal Government, the Local Government or any of the establishments, authorities, departments or any companies controlled or held by any of them directly or indirectly, and having at least 25 per cent of the shares of such companies" provided there is a special provision to this effect is contained in the memorandum of association or articles of association of such companies.

In any event, regardless of the potential exemption that exists under the Commercial Companies Law (or that existing under the old commercial companies law), in practice, both the Federal Government and the respective emirates regulate the ownership and acquisition by foreign companies of interests in the oil and natural gas sector as a matter of contract.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The UAE's environmental regime has developed in accordance with the UAE's international obligations. The UAE has ratified a number of important environmental treaties, including the Basel Convention on Hazardous Waste, the Convention on Marine Pollution by Dumping Wastes and Other Matter, the Convention on Biological Diversity, the Convention to Combat Desertification, the Kyoto Protocol on Climate Change and the Montreal Protocol on Substances that Deplete the Ozone Layer.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

There are no compulsory dispute resolution procedures that specifically apply to the oil and natural gas sector. Any decisions or disputes that affect a particular concession are governed in accordance with the terms of the applicable concession.

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13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

On 21 August 2006, the UAE acceded to the 1958 New York Convention on the Recognition and Enforcement of Arbitral Awards ("New York Convention"). The New York Convention entered into force in the UAE on 19 November 2006. In 2010, the Fujairah Court of First Instance recognised and enforced a foreign arbitral award pursuant to the New York Convention. This is understood to be the first enforcement of an award under the New York Convention in the UAE since the UAE's accession. However, although this was a landmark case, the enforcement was not contested; further, notwithstanding the judgment, there is no system of binding precedent in the UAE.

The Dubai Courts have since recognised and enforced a number of awards under the New York Convention; nonetheless, in 2012, the Dubai Court of First Instance also applied the provisions of the UAE Civil Procedures Code and refused to enforce three ICC/Paris awards, a ruling that was upheld by the Dubai Court of Cassation in 2013. More recently, though, in 2014 the Dubai Court of Cassation held that the New York Convention had the force of law in the UAE and that the Courts of Dubai should apply the provisions of the New York Convention to the execution of foreign arbitration awards.

Significantly, given the key importance of Abu Dhabi in the oil and natural gas sector, in 2013 the Abu Dhabi Court of Cassation reversed a decision of the Abu Dhabi Court of Appeal and enforced an ICC/Paris award, establishing a number of key principles consistent with the New York Convention. This is a positive judgment in relation to the commitment by the Abu Dhabi Courts to recognise and enforce foreign awards under the New York Convention.

The UAE ratified the ICSID Convention on 23 December 1981 and the ICSID Convention entered into force in the UAE on 22 January 1982.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

It is not possible to enforce judgments that seek to seize property owned by the state. Article 247(1) of the UAE Civil Procedure Code (Federal Law No. 11 of 1992, as amended) (the "Civil Procedure Code") provides that "public property owned by the state or one of the emirates" may not be seized for the purposes of enforcement. Public property is defined under the UAE Civil Transactions Code (Federal Law No. 5 of 1985, as amended) as all real property or movables owned by the state or public judicial persons, allocated in fact or in law for the public benefit.

With regard to the enforcement of foreign judgments, whether against a government authority, state organ or private entity, article 235 of the Civil Procedure Code provides that judgments and orders made in a foreign country may be executed in the UAE under the same conditions provided for in the law of that country for the execution of judgments and orders issued in the UAE. There is thus a requirement for reciprocal treatment. A number of conditions must also be satisfied, in practice affording UAE courts a wide discretion to reject enforcement of a foreign judgment on the basis of conflict or contradiction with previously passed orders or judgments of UAE courts and/or violation of public policy or public order. As a result, in the absence of a treaty between the UAE and the country concerned on mutual recognition and enforcement of judgments, in practice there are only limited circumstances when a foreign judgment is enforceable in the UAE.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are unaware of any such instances in the oil and natural gas sector.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

The UAE continues to consume more natural gas than it produces and imports have continued at a steady level during 2017. The UAE is aiming to diversify its energy supply through its nuclear programme, a number of world-leading renewable energy projects and the addition of coal to its energy mix. It is hoped that these diversification initiatives will free up natural gas for use by key industrial sectors, such as petrochemicals.

The main development in 2017 relates to the negotiations taking place for the ADMA-OPCO concession, which will expire in 2018. The renewal and splitting of the concession may well result in new players entering the Abu Dhabi market. How and to whom this concession will be awarded will have a major impact on the sector.

In 2017, ADNOC undertook a major restructuring exercise, incorporating most of its subsidiaries under its brand name and creating a centralised governance structure. Further to this restructuring, it has announced ambitious targets for expanding UAE production. As part of its broader strategy to manage its assets and increase value derived from across its businesses, ADNOC is also considering initial public offerings ("IPO") of ADNOC Group companies. In December 2017, 10 per cent of the shares in ADNOC Distribution were listed on the Abu Dhabi Stock Exchange, the first IPO on the exchange in six years. Established in 1973, ADNOC Distribution is ADNOC's fuel service station business. It currently holds almost 70 per cent of the fuel service station market share in the UAE. The IPO was oversubscribed multiple times and the share price surged within minutes of the opening of trading. While, at the time of writing, the IPO has only just gone live, if the positive response by the market is sustained, this may well lead to further IPOs of the ADNOC Group companies, with ADNOC reportedly considering listing further business units.

Sources for data concerning reserves, consumption, production and exports:

1. *OPEC Annual Statistical Bulletin 2017* (available at http://www.opec.org/).
2. *BP Statistical Review of World Energy June 2017* (available at http://www.bp.com/).

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Mhairi focuses in particular on upstream oil and gas projects (including acquisitions and disposals, development of upstream oil and gas projects, and sales arrangements) and utilities projects. She has advised on bid rounds, developments and acquisitions in multiple jurisdictions. Mhairi's expertise includes advising on issues of public international law related to oil and gas projects, including constitutional questions, BITs, sanctions and boundary disputes.

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United Kingdom

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

The United Kingdom ("**UK**") produced 41.0 billion cubic metres ("**bcm**") of natural gas in 2016 or approximately 1.2 per cent of the world's total production. This represents an increase of 3.3 per cent from 2015 production, continuing the year-on-year increases seen since 2014. The UK is the second largest producer of natural gas in Europe after Norway, having exceeded production levels in the Netherlands in 2016. The UK's proven reserves of natural gas as of the end of 2016 stood at 0.2 trillion cubic metres ("**tcm**"). The vast majority of these reserves are located in the UK sector of the North Sea ("**UKCS**").

The UK has been a net importer of gas since 2004. The UK imported a total of 44.6 bcm of natural gas in 2016 (via interconnector pipelines and via ships to LNG receiving terminals in the UK) – an increase from 42.1 bcm in 2015. The total gas imports in 2016 came from the following sources: 28.9 bcm from Norway (mainly by pipeline, but a small proportion as LNG); 4.1 bcm from the Netherlands (by pipeline); 1.4 bcm from other European countries (mainly by pipeline, but a small proportion as LNG); 9.6 bcm from Qatar (as LNG); 0.4 bcm from Algeria (as LNG); 0.1 bcm from Trinidad & Tobago (as LNG); and small quantities of LNG from Nigeria and Egypt.

Natural gas is imported into the UK via the following operational pipelines: the Bacton-Zeebrugge Interconnector; the BBL Pipeline between Balgzand in the Netherlands and Bacton in the UK; the Vesterled Pipeline between the Heimdal Riser Platform in the North Sea off the west coast of Norway and St Fergus in the UK; the Tampen Link which links Statfjord in the North Sea off the west coast of Norway to the Far North Liquids and Associated Gas ("**FLAGS**") pipeline (terminating at St Fergus in the UK); the Gjøa Pipeline, which links Gjøa/Vega off the coast of Norway to the FLAGS pipeline in the UK; and the Langeled pipeline between Nyhamna in Norway and Easington in the UK.

While pipeline imports remain a key feature of the energy mix in the UK, in recent years, LNG imports have become increasingly important. However, in 2016 LNG imports were reduced by 20 per cent compared to 2016. The reason for this was that higher demand in Japan and elsewhere in the world increased prices and reduced volumes supplied into Europe and the UK. In the UK, the shortfall was made up through a 20 per cent increase in pipeline imports, from Norway, Belgium and the Netherlands.

At present, the UK has three LNG import facilities:

- **Grain LNG** – this LNG import and regasification terminal on the Isle of Grain in Kent was commissioned in 2005 and was the UK's first LNG import facility. It is owned and operated by National Grid Grain LNG Limited, a wholly-owned subsidiary of National Grid plc ("National Grid").
- **South Hook LNG** – Qatar Petroleum (67.5 per cent), ExxonMobil (24.15 per cent) and Total's (8.35 per cent) 15.6 mtpa LNG import terminal at Milford Haven in Wales is the largest LNG receiving terminal in Europe. The terminal became operational in 2009. All of the primary capacity at the terminal has been purchased by South Hook Gas Company Ltd.
- **Dragon LNG** – Shell (50 per cent) and Petronas's (50 per cent) LNG import and storage terminal at Milford Haven in Wales received its first commissioning cargo in July 2009, with a start-up capacity of 4.4 mtpa.

Teesside GasPort at Teesside, the world's first dockside floating regasification terminal, was decommissioned in 2015 as it came to the end of its commercially viable life.

There are no LNG exports from the UK, nor any LNG liquefaction plants.

Until recently, the UK had a total of 4.82 bcm of storage capacity, at 10 commercial gas storage facilities. The most notable gas storage facility located in the UK is the offshore Rough Field long-range storage facility in the Southern North Sea (owned and operated by Centrica Storage, with a storage capacity of 3.1 bcm). Other depleted field gas storage facilities are located at Humbly Grove in Hampshire (Star Energy, 0.3 bcm) and Hatfield Moor in South Yorkshire (Scottish Power, 0.1 bcm), both of which are medium-range storage facilities. Onshore salt cavity storage facilities are located at Holehouse Farm in Cheshire (EDF Trading, 0.05 bcm), Hornsea in East Yorkshire (Scottish and Southern Energy, 0.3 bcm), Aldbrough in East Yorkshire (Statoil UK/Scottish and Southern Energy, 0.3 bcm), and Stublach (Storenergy, 0.2 bcm), Holford (E.ON, 0.2 bcm) and Hill Top Farm (EDF Energy, 0.02 bcm) all in Cheshire (again, all medium-range storage facilities). The UK has one small-scale short-range storage facility, Avonmouth near Bristol, to liquefy natural gas and store it as LNG, owned by LNG Storage, a trading division of National Grid Gas plc ("**NGG**"), with a capacity of 0.08 bcm.

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However, on 20 June 2017 Centrica, the operator of the Rough gas storage facility, announced its intention to permanently close the facility. This is a significant development for the UK gas market, because the Rough gas storage facility is the largest gas storage facility in the UK, representing more than 70 per cent of the UK's current gas storage capacity.

Natural gas is delivered to one of nine reception points in the UK, either by pipeline (from offshore facilities or pipelines which connect the UK to other countries) to beach terminals (the largest being situated at St Fergus in Scotland and Bacton, Easington and Teesside in England) or by ship to LNG receiving terminals. After treatment in the gas importation terminals, the processed natural gas is usually then piped into the National Transmission System ("**NTS**"), the high-pressure component of the UK's gas distribution network. The NTS, which is owned and operated by the National Grid, transports processed natural gas directly to end-users such as power stations and large-scale industrial users or to other offtake points, for distribution within 13 local distribution zones (which are grouped into eight regional gas distribution networks ("**GDNs**")). It is through the GDNs that the majority of the processed natural gas reaches domestic and commercial end users.

The UK continues to export significant volumes of gas by pipeline. In 2016, the UK exported a total of 10.0 bcm of natural gas to: Belgium (5.8 bcm); Ireland (2.7 bcm); and the Netherlands (1.6 bcm). The total was less than in 2015, largely due to the Corrib gas field off the Irish coast coming online and now supplying Ireland.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

In 2016, natural gas provided 42 per cent of the electricity generated in the UK. The remainder of the UK's electricity was generated predominantly by renewables (24.5 per cent), nuclear (21 per cent) and coal (9 per cent). Natural gas provided approximately 29.4 per cent of the UK's final energy consumption in 2016, with petroleum products accounting for 47.5 per cent of fuels used by final consumers and electricity for 17.5 per cent.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

The UK's natural gas requirements are not met entirely through domestic natural gas production. See question 1.1 above for specific details on imports.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

See question 1.1 above.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

The UK is a net importer of crude oil, but production levels from the UKCS remain significant. The UK's crude oil production capacity is the largest in the EU, and the second largest in the EEA after Norway. It is within the top 20 of oil producers worldwide. While production of crude oil and natural gas liquids from the UKCS has been in decline since 1999, the rate of decline slowed in 2014 due to the opening of new fields. The UK produced 1.013 million barrels a day in 2016, showing a 5.1 per cent increase on 2015.

There are currently six refineries in the UK, which process a significant proportion of the UK's oil into petroleum products. The six refineries produced nearly 60 million tonnes of product in 2016, down 1.7 per cent on 2015.

The refineries are supported by a network of petroleum product pipelines, as well as inland and coastal oil storage terminals. Oil is transported by pipeline, rail and by sea.

Despite the increase in production, the UK was a net importer of petroleum products in 2016 by 10.5 million tonnes, up from 9.2 million tonnes in 2015. Prior to 2013, the UK was consistently a net exporter of petroleum products but has since been a net importer.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

In 2016, petroleum products represented 47.5 per cent of the fuels used by final consumers (the other fuels being electricity and gas). The three main transport fuels – aviation turbine fuel, petrol and diesel – account for more than two-thirds of the UK's total demand for petroleum products.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

From its peak of 137 million tonnes in 1999, UKCS production has dropped nearly two-thirds to 47 million tonnes, with the UK becoming a net importer in 2005. Going forward, the UK will become increasingly reliant on crude oil imports. Norway has historically been the main source of UK crude oil imports, representing 62 per cent of all imports in 2016. Imports from OPEC countries accounted for 28 per cent of the UK's crude oil imports in 2016.

Similarly, notwithstanding its considerable refinery capacity, the UK also relies on petroleum product imports to meet local demand. Domestic supply and demand is not matched on a product-by-product basis, because UK refineries produce petrol and fuel oil for electricity generation. Therefore, the UK is one of the largest importers of jet fuel and road diesel in the OECD and one of the largest exporters of petrol.

2.4 To what extent is your jurisdiction's oil production exported (pipeline or LNG)?

The UK is a significant exporter of crude oils as well as an importer. Crude oil exports increased in 2016 to reach over 30 million tonnes. Crude oil has historically been principally exported to the Netherlands, Germany, France and the US, and more recently also to China. In 2016, China was the third largest recipient of UK crude exports after the Netherlands and Germany.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The principal legislation governing the development of oil and natural gas reserves is the Petroleum Act 1998 (as amended) (the

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"**Petroleum Act**"). Under the Petroleum Act, all rights to petroleum including the rights to "search for, bore for and get" petroleum are vested in the Crown. Until recently, the Secretary of State for Energy and Climate Change (the "**Secretary of State**") and the Department of Energy and Climate Change ("**DECC**") were primarily responsible for the regulation of the development of the UK's oil and natural gas resources. Following the recommendations of the Wood Review (discussed further below), the Government has established a new independent regulator, the Oil and Gas Authority (the "**OGA**"), to take over the licensing and regulatory oversight functions previously performed by DECC (and later the Department for Business, Energy and Industrial strategy ("**BEIS**")), on behalf of the Secretary of State. The OGA took over from DECC on 1 April 2015. Initially the OGA was established as an executive agency of DECC (and later BEIS). However, the Energy Act 2016 has established the OGA as a fully independent regulator, in the form of a Government-owned company, from 1 October 2016. The Energy Act 2016 has amended the Petroleum Act and associated legislation to formally vest various functions and powers, previously held by the Secretary of State, in the OGA. The OGA has also been vested with new powers relating to: the imposition of a wider range of sanctions to allow the OGA to enforce the regulatory regime; dispute resolution; collection of data and samples; and attendance by the OGA at meetings, such as operational committee meetings.

A Framework Document entered into between BEIS and the OGA governs the relationship between the OGA and the Government. In particular, the Secretary of State for Business, Energy and Industrial Strategy:

- continues to be responsible for the overall policy and legislative framework within which the OGA operates;
- is ultimately responsible to Parliament for the OGA; and
- must agree to any extension of the OGA's remit; any material deviation from the OGA's Corporate Plan; any changes to the MER UK Strategy (see below); and any decision to impose financial sanctions in excess of £1m.

BEIS (previously DECC) also retains responsibility for enforcement of the offshore environmental regime and decommissioning obligations. The Health and Safety Executive ("**HSE**") is responsible for enforcing the health and safety regime.

In recent years, it has been recognised that more needs to be done to incentivise investment and ensure that the upstream industry can continue to play an important role in the UK's economy. Therefore, in June 2013, the Secretary of State asked Sir Ian Wood to lead a review (the "**Wood Review**") of the challenges faced by the UK upstream offshore oil and gas industry. The final report was published in February 2014, and made various recommendations, including the establishment of a new regulator, as mentioned above. At the heart of the Wood Review and its concluding recommendations is the notion that a new approach is required to the management and oversight of the UK Continental Shelf ("**UKCS**"), and that maximising economic recovery ("**MER UK**") is the key principle underlying the new approach. The Infrastructure Act 2015 amended the Petroleum Act to include a new Part 1A, to provide for the development and implementation of the MER UK Strategy. The MER UK Strategy, produced by the Secretary of State in consultation with industry, came into force on 18 March 2016. The Strategy is binding on: the Secretary of State; the OGA; various industry players, including holders of offshore petroleum licences; operators; and owners of relevant offshore installations. The OGA has the power to enforce compliance with the Strategy. For the time being at least, the Strategy only applies to offshore oil and gas operations.

Government policy has also recently focused on facilitating the development of a shale gas industry. In particular, the Government has published various detailed guidance for the industry on the applicable regulatory consents, introduced some reforms to the planning regime, and offered tax incentives. The Government has also implemented reforms to the land access regime for underground drilling, pursuant to the Infrastructure Act 2015.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

Until recently, the Petroleum Act empowered the Secretary of State to grant licences to explore for, develop and produce oil and natural gas reserves. However, the Petroleum (Transfer of Functions) Regulations 2016 have now vested the power in the OGA. Moreover, new devolution settlements for Scotland and Wales, under the Scotland Act 2016 and the Wales Act 2017 respectively, have vested onshore licensing powers in the Scottish Ministers in respect of Scotland and the Welsh Ministers in respect of Wales. Offshore licensing is unaffected by devolution.

In awarding licences, regard must be given to the Hydrocarbons Licensing Directive Regulations 1995, which implement certain EU directives in relation to hydrocarbon licensing that were passed in 1994. Licences are usually awarded in licensing rounds where a large number of blocks are made available. On 25 July 2017, the OGA invited applications for licences in the 30th Seaward Licensing Round.

In addition, on 28 July 2014 the 14th Landward Licensing Round was launched, for companies seeking licences to explore for onshore oil and gas. The Landward Licensing Round was of particular interest to companies seeking to participate in the UK's fledgling shale gas industry.

"**Out of round**" licences may also be granted in certain circumstances.

Licences take the form of a deed, pursuant to which the licensee is bound to observe the conditions of the licence. The conditions of the licence (referred to as the "**Model Clauses**") are published in secondary legislation. The secondary legislation applying to current licence awards are:

- the Petroleum Licensing (Exploration and Production) (Seaward and Landward Areas) Regulations 2004 for exploration, production and exploration and development licences for the 12th and subsequent licensing rounds for landward areas, and 22nd and subsequent licensing rounds for seaward areas;
- the Petroleum Licensing (Production) (Seaward Areas) Regulations 2008 for seaward area production licences for the 25th and subsequent licensing rounds; and
- the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 for landward petroleum exploration and development licences issued in the 14th and subsequent landward licensing rounds, as well as new landward exploration licences.

The Model Clauses attached to existing licences are not affected by the issue of subsequent sets of Model Clauses, except through specifically retrospective measures. While most licences follow a standard format, the OGA may consider adapting licence terms in some circumstances.

UK licences are both contractual and regulatory in nature: contractual, being executed as a deed providing for the contractual transfer of rights from the Crown to the licensee to develop petroleum resources in return for a financial reward; and regulatory, because the Model Clauses are embodied in statutory regulations, and the terms upon which a licence is granted may be unilaterally amended by Parliament. Licences may be granted to one or more

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licensees; however, legally only one licence exists which is held collectively by the licensees who are jointly and severally liable in respect of obligations arising under, and operations conducted pursuant to, the licence.

It is important to note the distinction in the UK between the application of English law and Scottish law in the UKCS (and to a lesser extent, Northern Irish law in non-North Sea fields). Although the Model Clauses applying to licence awards in English and Scottish areas of the UKCS will be substantially the same, the jurisdictional distinction is particularly important as different arbitration provisions will apply to a licence, depending on whether it is situated in the English or Scottish area of the UKCS (see question 13.1 below). The Isle of Man issues licences for its own onshore area and territorial waters. Similarly, the devolved Government in Northern Ireland issues licences for onshore areas in Northern Ireland.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

The most common types of offshore licences are the traditional Seaward Production Licence ("**SPL**") and the Exploration Licence. In recent years, the Secretary of State has also issued three variations on the SPL to take account of the particular circumstances of the field, being: Promote Licences; Frontier Licences; and licences specifically drafted to cover the redevelopment of a decommissioned field (e.g. Argyll/Ardmore). Most recently, the OGA has introduced a new variation on the traditional SPL – the Innovate Licence. The OGA has said that from the 29th Licensing Round, all new offshore production licences will become Innovate Licences, "offering greater flexibility for each applicant to design a work programme around particular circumstances". The introduction of the "Innovate Licence" has no impact on licences already issued.

For onshore exploration and production activities, a Petroleum Exploration and Development Licence ("**PEDL**") is required. Most recently, the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 introduced model clauses to allow an onshore Exploration Licence to be granted for a term of three years.

The different types of licences, in more detail, are as follows:

- **Offshore Exploration Licence**: A non-exclusive offshore Exploration Licence enables the licensee to carry out exploratory seismic surveys over large unlicensed geographical areas of the offshore sector where an SPL would be impractical and prohibitively expensive, in return for a modest annual rental payment. Such licences are typically granted for a three-year term (with the possibility of a further three-year extension if certain terms and conditions have been met). Exploration drilling below certain depths (typically 350 metres) is usually not permitted.
- **Offshore SPL**: A SPL is usually granted in respect of a relatively small geographical area (typically, not more than several hundred square kilometres) on the UKCS. It covers the full life of a field from exploration to decommissioning. It grants the licensee the exclusive right to undertake various activities within defined phases, which are: exploration (typically four years); appraisal, during which the licensee must draw up and submit a field development plan (four years); and production of oil and natural gas (18 years, with a possibility of extension). The licence will expire at the end of each phase unless the licensee has made sufficient progress to move to the next phase. Typically, the licensee must surrender 50 per cent of its acreage at the end of the exploration phase and all acreage not covered by the field development plan at the end of the appraisal phase. An annual rental payment is payable, which is proportional to the acreage covered by the licence and which escalates each year after the initial exploration period.
- **Offshore Promote Licence**: A Promote Licence is similar to the traditional SPL, with the term of the various phases being the same. However, the Promote Licence allows a licensee to hold the licence (and, therefore, assess future prospects) for up to two years before it must satisfy the stringent entry checks required under the traditional SPL. Promote Licensees are not permitted to carry out any exploration activities until they have satisfied the entry checks and given a firm commitment to complete an agreed work programme. Licensees benefit from a 90 per cent discount on rental fees, payable under a traditional SPL for the first two years.
- **Offshore Frontier Licence**: Frontier Licences grant a licensee the right to explore a relatively large amount of acreage, which is considered to be difficult or unexplored. There are two types, providing an initial term of either six or nine years, the latter designed for the particularly harsh environment of the West of Scotland. 75 per cent of the acreage will be relinquished after an initial screening phase of three years, and 50 per cent after the initial term. Licensees benefit from a 90 per cent discount on rental fees for the initial screening phase and extended exploration and appraisal periods (an additional two to five years for the exploration phase and two years for the appraisal phase) from those granted under the traditional SPL.
- **Onshore PEDL**: The onshore PEDLs are similar in form to the offshore SPL and include Model Clauses and a three-phase lifespan. Licensees are granted the exclusive right to explore for, and exploit, petroleum in a specified area. The exploratory phase for onshore PEDLs is six years; the appraisal phase is five years; and the production phase for a PEDL is 20 years, subject to a governmental discretion to extend. Licensees are required to relinquish 50 per cent of the acreage at the end of the exploration phase. However, under the new model clauses set out pursuant to the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014, the usual obligation to relinquish at least half of the initial licensed area is now subject to a new power for the OGA to agree with the licensee to the creation of so-called Retention Areas and Development Areas. Where this is agreed, the licensee may retain the Retention Areas and Development Areas into the second term. During the production period, the OGA may remove acreage that is not comprised in either a Retention Area or a Development Area.
- **Innovate Licence**: One of the key features of the Innovate Licence is that it has an initial term of up to nine years which is divided into three phases: phase A, for studies and reprocessing; phase B, for shooting new seismic; and phase C, for drilling wells.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

As a matter of law under the Petroleum Act, all rights to oil and natural gas are vested in the Crown. However, the state does not participate directly in oil and natural gas production, other than having an economic interest in the development of oil and natural gas through the imposition of acreage rental and certain taxes (see question 3.5 below). The UK no longer has a state petroleum company, and oil and natural gas development is carried out entirely

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by private companies or foreign state-owned companies under licences granted by the Secretary of State or the OGA.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

The taxation regime that applies to profits derived from oil and gas production in the UK and the UK Continental Shelf is made up of three main components, summarised below. In the past, a royalty regime applied, but this was abolished from 1 January 2003. In recent times, the Government has taken steps to reduce the tax payable by oil and gas companies, to encourage further investment and also in response to the lower oil price.

- **Petroleum Revenue Tax (PRT)**: PRT technically applies to net income from oil and gas extraction, but only in respect of those fields for which development consent was given prior to 16 March 1993. Ring Fence Corporation Tax and the Supplementary Charge (see below) are also payable in respect of profits from these fields, but PRT is deductible when calculating these charges. PRT was originally levied at a rate of 50 per cent, and was reduced to 35 per cent from 1 January 2016. However, it was announced in the UK Budget in March 2016 that PRT would be effectively abolished and the rate of PRT would be reduced to zero for all chargeable periods ending after 31 December 2015.
- **Ring Fence Corporation Tax (RFCT)**: RFCT applies to profits from oil and gas extraction activities and rights in the UK and UKCS instead of normal Corporation Tax. It applies regardless of when development consent was given, and aims to prevent profits from these activities being reduced for tax purposes by the setting off of losses from other non-oil and gas related trading activities. The profits from oil and gas extraction activities and rights are "ring fenced" and treated for tax purposes as a separate trade, so that only losses derived from these activities can be set off against profits from these activities. The current rate of RFCT is 30 per cent (*versus* 19 per cent for "non-ring fence" profits). RFCT liabilities are based on the book profits of the company which are then adjusted to arrive at the taxable profits. Deductions are available for items such as capital expenditure, plant and machinery allowances, research and development, expenditure on mineral exploration and access, and decommissioning.
- **Supplementary Charge**: A Supplementary Charge is also imposed on profits arising from any ring-fenced activities. The Charge was first introduced in 2002, at a rate of 10 per cent. In 2011, the Government raised the rate of the Supplementary Charge from 20 per cent to 32 per cent. The Government's rationale was that the rise in oil prices had provided unexpected profits for oil and gas companies. Following a fiscal review launched in 2014 the Supplementary Charge was reduced to 30 per cent and was subsequently further reduced to 20 per cent from 1 January 2015 and has now been further reduced to 10 per cent with effect from 1 January 2016.
- **Field allowances**: In order to encourage development of remaining reserves, a system of "field allowances" was introduced in 2009, to apply to small or new, technically challenging fields (for example, deep-water gas fields and ultra-heavy oil fields). A field allowance reduces the amount of adjusted ring fence profits for the licensee's accounting period on which the company's Supplementary Charge is charged.

An annual charge, called a rental, is also payable under each licence. Rentals are charged at an escalating rate on each square kilometre the licence covers at that date. This method of calculating the rental provides an incentive to licensees to surrender acreage they do not want to exploit. The amount of the rental is relatively small. Taxation, discussed above, is the main means by which the Government derives revenue from oil and gas resources.

3.6 Are there any restrictions on the export of production?

There are no restrictions on the export of production. See question 4.1 below for the regulatory regime that applies to gas interconnectors.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are no restrictions on currency exchange or on the transfer of funds derived from production out of the jurisdiction.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The OGA's consent is required before any transfer of a licence interest can be made, including a transfer to an affiliate. The transfer approvals process has in recent years been streamlined in line with the general policy to encourage the transfer of licence interests. For offshore licences the application for consent to licence assignment must be made using the OGA's e-licence administration system (PEARS: the Petroleum E-Licensing Assignments and Relinquishments System). For onshore licences, currently the process requires the licensee wishing to transfer its licence interest to advise the OGA by lodging a standard application form, although it is intended that in due course the assignment of onshore licences will also be processed using the PEARS online administration system. The OGA reserves the right to seek further information once an application is made. The consent to transfer a licence is conditional upon the parties executing a deed of assignment, which needs to conform substantially to the template assignment deeds previously approved by the Secretary of State, of which there are currently two. The parties may submit different drafts to the OGA; however, this may increase processing time. The OGA will usually approve the transfer; however, it will have particular regard to the technical and financial capability of the proposed transferee, in particular, where the proposed transferee is likely to have to bear some of the decommissioning costs in respect of the field. The OGA is likely to undertake a more detailed assessment if the proposed transferee is a new entrant into the UK upstream petroleum industry or if the transfer would result in a change of operatorship.

In some circumstances, the OGA may provide an opinion of "**no objection in principle**" to a proposed transfer, which is to occur at some point in the future after the transferee and proposed transferee have made financial commitments (such as earn-in arrangements).

On a change of control of a licensee, the Model Clauses do not impose any requirement for the OGA's approval. However, the OGA has the power to require the licensee to procure a further change in control and a failure to comply with such requirement is specified as a ground for revoking a licence under the Model Clauses. In practice, licensees who are the subject of a change of control usually request an assurance from the OGA that this power will not be exercised.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

In considering whether to award a licence or approve a licence

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assignment, the OGA will have regard to the financial capacity of the proposed licensee. The OGA will not consent to an award or assignment if the company is not able to demonstrate its ability to meet its expected financial commitments, liabilities and obligations under the licence or if the company is insolvent or appears likely to become insolvent. Each licence applicant must demonstrate to the OGA's satisfaction that it is financially viable and it is likely to continue business for the foreseeable future; and that it has sufficient financial capacity to fund its share of the anticipated work, meeting costs within a reasonable timeframe and decommissioning costs.

If the company has a parent company with significant financial capacity, the OGA may require a parent guarantee to support the company's financial obligations either under the company's existing licences and any future licences to which the company becomes party, or on a licence-by-licence basis.

As production licences confer exclusive rights, all the appropriate technical and financial capacity to contribute to the delivery of MER UK is an important criterion for the acceptability of a company to be a licensee. In addition, there are other requirements of licensees such as the establishment of a tax base, finance, residence and organisational structure and for offshore licensees there are safety and environmental capability requirements under the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.

Under the Petroleum Act, the Secretary of State may require a person to take action where it is not satisfied such person will be capable of carrying out its decommissioning obligations (which may include the provision of security, such as a letter of credit) in order to reduce the risk to the UK taxpayer (who would otherwise bear this liability). It also obliges companies to provide adequate financial information (including management accounts and revenue predictions) in order to enable the Secretary of State to assess whether decommissioning security ought to be provided at an earlier stage. Any funds set aside in a secure manner (such as a trust or other arrangement which was established on or after 1 December 2007) to meet decommissioning obligations will not be accessible to creditors under insolvency legislation.

The Secretary of State may also require participants to enter into a Decommissioning Security Agreement ("**DSA**"), where it is deemed that the participants may be unable to pay for decommissioning costs following any request to submit a decommissioning programme (see question 3.12 below) to which the Secretary of State may or may not be a party. Circumstances in which the Secretary of State may become a party to a DSA include (in order to facilitate the withdrawal of a section 29 notice (see question 3.12)), where a party is exiting the licence, to ensure changes to the DSA cannot be made without the Secretary of State's consent or to facilitate action by the Secretary of State to resolve a default situation. BEIS does not prescribe a standard form DSA, but the agreement must meet certain minimum requirements if the Secretary of State is a party. The minimum requirements include: an obligation on the parties to provide security (cash, irrevocable standby letters of credit issued by a Prime Bank (as defined in BEIS Guidance Notes), or on demand performance bonds from Prime Banks would normally be acceptable) (to be renewed annually) sufficient to cover each party's respective share of decommissioning costs; and a requirement for the total security to equal at least 100 per cent of the expected decommissioning costs for the installations and pipelines in the field covered by the DSA (minus the amount of any expected share of remaining reserves) (plus, in most cases, an additional 50 per cent to cover uncertainties around the cost calculations).

Oil & Gas UK, the industry body for the UK offshore oil and gas industry, published a template DSA in 2006 in response to widespread calls and after a lengthy industry-wide consultation and drafting process. This template DSA functions as a flexible stand-alone agreement and is now often negotiated along with the joint operating agreement prior to approval by BEIS of the field development plan for a new field, or on the next transfer of an interest in the relevant licence for an existing development.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

The creation of charges over licence interests is subject to the conditions under the Model Clauses attached to each licence, requiring consent from the OGA (previously the Secretary of State). However, in most cases, licensees are not required to apply for individual consent. The Open Permission (Creation of Security Rights Over Licences), granted by the Secretary of State on 6 February 2012, still applies and automatically grants consent to the creation of a variety of charges over licences, including fixed or floating charges and debentures, on the condition that the licensee notifies the OGA within 10 days of the creation of the security of:

- the date of creation of the security;
- the amount of money or other liabilities to be secured by the charge;
- which licences are the subject of the security; and
- the identity of the chargee.

The fact that a proposed security interest falls outside the scope of the Open Permission does not mean that the creation of such a security interest will not be approved, rather that it will be subject to the OGA's individual approvals process.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

While oil and natural gas development is principally regulated and controlled through the terms of the licence, various statutory controls also exist. The main statutory controls relating to offshore oil and natural gas development in England and Wales (separate controls will apply in some cases in relation to Scotland) include, under the following broad categorisations and as amended:

Environmental

- Ozone-Depleting Substances Regulations 2015.
- Environmental Protection Act 1990.
- Fluorinated Greenhouse Gases Regulations 2015.
- Food and Environment Protection Act 1985.
- Greenhouse Gas Emissions Trading Scheme Regulations 2012.
- Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998.
- Merchant Shipping (Prevention of Pollution by Sewage and Garbage from Ships) Regulations 2008.
- Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015.
- Offshore Chemical Regulations 2002.
- Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013.
- Offshore Installations (Emergency Pollution Control) Regulations 2002.

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- Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001.
- Offshore Marine Conservation (Natural Habitats, etc.) Regulations 2007.
- Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005.
- Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999.
- REACH Enforcement Regulations 2008.
- Marine and Coastal Access Act 2009.
- Energy Act 2008.

Health and Safety

- Health and Safety at Work etc. Act 1974.
- Health and Safety at Work etc. Act 1974 (Application outside Great Britain) Order 2013.
- Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995.
- Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996.
- Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995.
- The Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015.
- Pipelines Safety Regulations 1996.
- Offshore Installations (Safety Zones) Regulations 1987.

The regulators and organisations in England and Wales (these may be different for operations in Scotland and Northern Ireland), from whom authorisations may need to be obtained or who may need to be consulted, include BEIS, the HSE and the Department for Environment, Food and Rural Affairs, and their relevant departmental units, the Joint Nature Conservation Committee or coastal conservation bodies such as Natural England.

The Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015, and the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015 were enacted in 2015 to implement the requirements of the EU Offshore Safety Directive (2013/30/EU). The EU adopted the Offshore Safety Directive on 10 June 2013 as a direct response to the Deepwater Horizon disaster. The Directive required the creation of an offshore Competent Authority. BEIS and the HSE, working in partnership, have established the Offshore Safety Directive Regulator ("**OSDR**") to act as the UK's Competent Authority for the purposes of the Directive. The role of the OSDR is to oversee industry compliance with the Directive and to undertake related functions such as accepting, assessing, approving and/or inspecting relevant Safety Cases, Oil Pollution Emergency Plans, Well Notifications and other notifications.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

The decommissioning of offshore installations and pipelines is regulated under Part IV of the Petroleum Act. Responsibility for ensuring compliance rests with the Offshore Petroleum Regulator for Environment and Decommissioning, which is part of BEIS. In contrast, the decommissioning of onshore installations is partly governed by local planning rules. The main objective of the decommissioning regime under the Petroleum Act is to ensure that the cost of decommissioning is not borne by BEIS and, therefore, tax payers.

While responsibility for the offshore decommissioning regime remains with BEIS, rather than the OGA, the Energy Act 2016 did make some amendments to the decommissioning regime to recognise the OGA's role and the drive towards cost reduction and collaboration. In particular, before the Secretary of State approves a decommissioning programme (see below), he or she must first consult the OGA.

Decommissioning obligations arise when the Secretary of State serves a notice (a "**section 29 notice**") to the operator of the field and each of the licensees, requiring them to submit a decommissioning programme (referred to in the legislation as an "abandonment" programme). Once the decommissioning programme is approved, following BEIS's review of the detail including the cost estimates, the section 29 notice-holders are legally obliged to carry it out on a joint and several liability basis.

BEIS will usually request the submission of a decommissioning programme three or more years before cessation of production, although for smaller fields BEIS may require a programme at the time of approval of the final field development plan. BEIS may also serve a section 29 notice on:

- any person having an ownership interest in the installation or pipeline;
- a parent company or associated companies of a licensee;
- any person intending to carry on specified activities in relation to the installation or pipeline in the future;
- any transferor of an interest in an offshore installation or pipeline where such transferor has failed to obtain the consent of the Secretary of State to the transfer; and
- any licensee and parties to joint operating or similar agreements in relation to a petroleum exploration or extraction licence, regardless of whether such party benefited or had the potential to benefit from the particular installation.

Typically, BEIS will utilise this wider class of parties if it is of the view that the decommissioning arrangements proposed by the operator and licensees are unsatisfactory. In addition, and crucially, section 34 of the Petroleum Act extends the right to issue a section 29 notice to anyone who, at any time since the first section 29 notice for the installation is issued, was liable to have a section 29 notice served on it, i.e. former licensees.

Until such time as the section 29 notice has been withdrawn, the licensee remains liable for decommissioning obligations. When an asset changes hands, the Secretary of State may release a former licensee from its section 29 obligations. In most cases, the section 29 notice will be withdrawn, provided that BEIS is satisfied that an adequate DSA is in place (see question 2.9 above). However, in some circumstances the Secretary of State may use its "claw-back" power under section 34 to impose liability on a party previously released from its decommissioning obligations.

A new Decommissioning Relief Deed regime gives the Government statutory authority to sign contracts (referred to as Decommissioning Relief Deeds) with oil and gas companies to provide them with certainty about the tax relief they will receive for the cost of decommissioning assets.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

A different regulatory regime applies to the development of gas storage projects, depending on whether the project is onshore or offshore. A third-party access regime also applies.

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The Energy Act 2008 created a new offshore gas storage licensing regime, which entered into force on 13 November 2009, in respect of gas storage and recovery of stored gas, or unloading of gas to installations or pipelines within the offshore area, comprising both the UK territorial sea and the defined "Gas Importation and Storage Zone" area beyond. For any initial non-intrusive exploration activities, a developer of a potential gas storage project will be granted a standard offshore exploration licence in the same way as for any other petroleum exploration activities under the Petroleum Act, for a term of up to three years (with a possible extension of a further three years). Following this initial phase, a developer will need to apply for a gas storage licence, which will have separate exploration, appraisal and production phases and its duration will be determined on a case-by-case basis. The licence will import Model Clauses and will also require the developer to submit a gas storage development plan to the OGA for approval.

In addition, offshore gas storage facilities also require a contractual grant of rights (in the form of a lease or authorisation) from, and on the payment of consideration to, the Crown Estate Commissioners, under the Crown Estate Act 1961.

In respect of onshore gas storage projects, one permitting route is under section 4 of the Gas Act 1965, which provides for licensed gas transporters to obtain a storage authorisation order from the Secretary of State in order to develop or use underground natural porous strata for the storage of gas. The more usual permitting route for onshore gas storage projects is under the Planning Act 2008. Under the Planning Act 2008, an onshore underground gas storage project must be authorised by a development consent order granted by the relevant Secretary of State (following an application to the Planning Inspectorate) if the working capacity of the facility is expected to be at least 43 million standard cubic metres, or the maximum flow rate is expected to be at least 4.5 million standard cubic metres per day. Facilities which are configured below those thresholds will remain within the jurisdiction of the local planning authorities.

Gas storage facilities must also comply with health and safety and pollution control regulations. Where a depleted gas reservoir is being converted into a gas storage facility, a petroleum licence is also likely to be required.

Finally, gas storage facilities are subject to the third-party access regime under the European Gas Directive 2009/73/EC (the "**Third European Gas Directive**") and the Gas Regulation which also forms part of the EU's Third Energy Package. The Directive allows Member States to choose between negotiated third-party access rights ("**nTPA**"), where third parties must be able to negotiate rights of access to gas storage facilities on the basis of good faith negotiations leading to a voluntary commercial agreement, and regulated third-party access rights ("**rTPA**"), where third parties must be given a right of access to gas storage facilities on the basis of published tariffs. The UK has implemented the nTPA regime.

Under UK law, third-party access ("**TPA**") rights in relation to gas storage, both onshore and offshore, are principally regulated by the Gas Act. Under this legislation, unless it has been granted a TPA exemption, the owner of a gas storage facility is required to publish its main commercial conditions of contract for access to storage capacity at least once a year, and must ensure that such conditions do not discriminate against any potential applicants. If a third party makes an application for access, then the owner of the facility must negotiate in good faith and endeavour to reach an agreement with the applicant for storage capacity. If the parties are unable to reach agreement, the party seeking access can apply to Ofgem to consider the application and for Ofgem to give any appropriate directions to the facility owner to grant access if this would not prejudice the efficient operation of the facility.

Exemptions from the application of third-party access rights may be granted where Ofgem is satisfied that use of the facility by other persons is not necessary for the operation of an economically efficient gas market (the *de minimis* exemption), or where the following conditions are met (sometimes referred to as the Article 22 exemption):

- the facility (or the significant increase in capacity) will promote security of supply;
- the level of risk is such that the investment to construct or to modify the facility would not be made without the exemption;
- the facility will be owned by a person other than the connected gas transporter;
- charges will be levied on the users of the facility or the increase in capacity;
- the exemption will not be detrimental to competition, the operation of an economically efficient gas market, or the efficient functioning of the connected pipeline system; and
- the European Commission is or will be content with the exemption.

The Article 22 exemption derives from Article 22 of the European Gas Directive 2003/55/EC, and is restated in Article 36 of the Third European Gas Directive.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

In general, any person participating in the operation of a gas interconnector must hold a Gas Interconnector Licence issued by Ofgem under the Gas Act (see question 7.1 below for a more detailed discussion of the downstream gas market regulatory regime). "Participating" includes co-ordinating and directing the conveyance of natural gas into, or through, a gas interconnector, or making a gas interconnector available for the conveyance of natural gas. The holder of a Gas Interconnector Licence cannot hold a Gas Transporter Licence, Gas Shipper Licence or Gas Supplier Licence (see question 7.1 below).

The construction of a gas interconnector will need to comply with the regulatory requirements, applying in respect of the construction of offshore pipelines and infrastructure (see question 6.2 below).

Gas interconnectors are subject to the rights of third-party access under the Gas Act 1995 (see question 6.6 below for further details).

Each gas interconnector will have an international treaty associated with it. The treaty will apply in addition to UK legal requirements and will usually clarify various legal, technical and safety issues relating to the gas interconnector.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

There are no special regulatory requirements that apply to the cross-border imports or exports of oil or oil products, other than the payment of any customs duties or taxes applicable, and compliance

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with any of the applicable requirements discussed in question 10.1 below. From time to time, specific limitations may apply, such as the restrictions on trade with Iran that applied until recently. Also, in the event of an actual or threatened emergency in the UK that will affect fuel supplies, the Secretary of State may use emergency powers under the Energy Act 1976 to regulate or prohibit the production, supply, acquisition or use of substances used as fuel.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Offshore and onshore pipelines and associated infrastructure are subject to different legal regimes in the UK. This section will focus on offshore infrastructure because the majority of the UK's oil and natural gas production is derived from offshore fields in the UKCS. Offshore infrastructure includes offshore platforms and pipelines, onshore gas processing terminals and pipelines connecting those terminals to the NTS.

Offshore infrastructure is generally constructed, owned and operated by private companies – in most circumstances, by licensees developing offshore oil and natural gas fields. Given that the UKCS has been in production for over 40 years, there is a well-established network of offshore infrastructure bringing oil and natural gas production ashore.

The construction and operation of offshore infrastructure is principally governed by the Petroleum Act. The terms of the applicable production licence and field development programme approved by the OGA (previously by DECC) will also regulate the construction and operation of offshore infrastructure to a large extent.

For the regulatory framework relating to gas storage facilities, please see question 3.13.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The construction and operation of offshore infrastructure must be carried out in compliance with the terms of the applicable production licence. The Model Clauses applicable to a production licence (refer to question 3.2 above) prohibit licensees from installing any permanent structures or carrying out any works for the purpose of extracting petroleum from an area or conveying petroleum to a place on land without the authorisation of the OGA (previously the Secretary of State) or without having a development and production programme in place which the OGA has either approved or served on the licensee. The Model Clauses also set out the process pursuant to which programmes are prepared and submitted by the licensee and either approved or rejected by the OGA (previously the Secretary of State).

To construct an offshore pipeline, a Pipeline Works Authorisation ("**PWA**") issued by the OGA (previously the Secretary of State) under the Petroleum Act is required. The Energy Act 2008 expanded the definition of offshore pipelines to include "all apparatus, works and services associated with the operation of such a pipe or system". This includes pipelines used for the conveyance of hydrocarbons, water, chemicals, apparatus for the supply of energy for operations, hydraulic control lines or umbilicals, as well as services (for example, the provision of fuel or power). The PWA will usually be issued to the operator of the licensee group wishing to construct the pipeline (the "**holder**") and will authorise the licensees (the "**users**") to use the pipeline and apparatus.

Under the terms of the PWA, the holder may be named as operator. The operator will be responsible for organising or supervising the construction and operation of the pipeline and ensuring compliance with all relevant legislation prevailing at the time. The holder must also provide the OGA with advance notice of any proposed modifications to the pipeline and any changes to the holder, owners, users or operator of the pipeline.

See question 3.11 for further Government regulatory controls, including environmental and health and safety.

A party wishing to construct certain onshore pipelines must obtain a pipeline construction authorisation from the Secretary of State, pursuant to the Pipe-lines Act 1962 (as amended). The proposed pipeline owner must demonstrate to the Secretary of State that it has consulted with certain bodies, most notably local authorities, and landowners and occupiers affected by the proposed pipeline routing. The application must specify the rights and consents required to enable the pipeline to be constructed, and the extent to which the applicant has been successful in obtaining such consents. Where the applicant has been unable to negotiate access rights or easements by way of voluntary agreement with land owners or occupiers, subject to the Secretary of State approving the application, the applicant may be entitled to exercise powers of compulsory purchase pursuant to the Pipe-lines Act 1962. Onshore pipelines which are to be constructed by Gas Transporters and which meet the criteria set out in the Planning Act 2008 require development consent instead of a pipeline construction authorisation under the Pipe-lines Act 1962.

With the exception of certain pipelines, the environmental management of onshore pipelines (and the onshore hydrocarbon industry generally) is primarily overseen by the Department for Environment, Food and Rural Affairs, the Environment Agency (in England), Natural Resources Wales (in Wales), the Scottish Environmental Protection Agency (in Scotland) and local authorities. Any party wishing to own, construct and/or operate any onshore pipeline must have regard to the requirements of both UK and EU environmental legislation.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

In relation to onshore oil and gas pipelines, the Secretary of State has powers under the Pipe-lines Act 1962 to authorise a person proposing to construct a pipeline to compulsorily acquire land if a voluntary arrangement cannot be reached between such party and the land owners, lessees and occupiers of the land in question. In relation to offshore pipelines, the consent of the Crown Estate is necessary for all oil and gas pipelines that cross the seabed within UK territorial waters (12 nautical miles of the coastline).

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

A licensee wishing to develop offshore oil and gas fields in close proximity to existing infrastructure will usually seek to negotiate access arrangements (e.g. gas transportation agreements) with the

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infrastructure owners. If the licensee is unable to agree a satisfactory access arrangement with the infrastructure owners, then the licensee may apply to the OGA to require access to be granted.

Please refer to question 6.6 for information on the third-party access regime.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

Because offshore pipeline systems are generally privately owned, licensees wishing to connect new pipelines into existing pipeline systems or to interconnect existing pipeline systems will generally need to negotiate contractual arrangements with the existing pipeline owners. Rights of third-party access are discussed in more detail in question 6.6 below.

Any connection of new pipelines to existing offshore pipeline systems will also need to comply with the authorisations and requirements referred to in question 6.2 above.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

The Energy Act 2011 sets out the third-party access regime that applies to all upstream oil and gas pipelines and processing facilities. Under the regime, owners of upstream infrastructure are required to publish annually their main commercial conditions for access. Third parties wishing to obtain access to such facilities negotiate in good faith directly with the owners in the first instance on the basis of these published commercial terms. Where a party that seeks access to upstream oil and gas infrastructure cannot agree rights of access with the owner, it has the right to apply to the OGA (previously the Secretary of State) for a notice granting the relevant rights. The OGA may consider such an application only if he or she believes that the parties have had reasonable time in which to reach an agreement. In exercising its powers to determine third-party access disputes, the OGA is required to act in accordance with the MER UK Strategy, as well as various factors set out in section 82 of the Energy Act 2011, which include, among other things:

- the capacity which is or can reasonably be made available in the pipeline or facility in question;
- any incompatibilities of technical specification which cannot reasonably be overcome; and
- difficulties which cannot reasonably be overcome and which could prejudice the efficient, current and planned future production of petroleum.

If the OGA decides that access should be granted it may serve a notice to that effect on the parties. This may allow for such things as: connections to be made to the owner's infrastructure; authorise the owner to recover any necessary payments from the applicant; and set out the terms of access. In deciding the terms on which any access should be granted, one of the main issues is the need to identify the relevant costs and risks and to decide on fair and appropriate terms. These will have to be decided on a case-by-case basis.

Importantly, the OGA can issue an access notice under his own initiative, where parties have had reasonable time in which to reach an agreement and there is no realistic prospect of an agreement being reached.

The Energy Act 2011 regime was amended by the Energy Act 2016 to vest the relevant powers in the OGA, and to introduce some reforms to the regime. In particular, the Energy Act 2016 introduced some changes to the regime to ensure that the application process does not need to be restarted where there is a change in ownership of the relevant assets or interests.

The Code of Practice on Access to Upstream Oil and Gas Infrastructure on the UKCS (the "**Infrastructure Code of Practice**") was launched in 2004 (and since revised, most recently in August 2017) to help open up access to infrastructure on the UKCS for new users so that small adjacent fields could be made economically viable. It provides a framework to oil and gas infrastructure owners and users for the process which should be followed in seeking, offering and negotiating access to offshore infrastructure. The Infrastructure Code of Practice applies to offshore and onshore oil and gas infrastructure up to the point that natural gas enters into the NTS. The Infrastructure Code of Practice is intended to clarify, streamline and facilitate the timely resolution of access requests on a negotiated, non-discriminatory basis. The Infrastructure Code of Practice is voluntary and is not legally-binding. As such, it does not fetter the OGA's discretion under the relevant legislation but where an application is made to the OGA to exercise its statutory powers relating to third-party access disputes, the OGA will consider the extent to which the parties involved have adopted the Infrastructure Code of Practice's procedures.

The Gas Act 1995 deals with third-party access to downstream gas processing facilities – that is, facilities not covered by the Energy Act 2011 regime, described above. The provisions in the Gas Act 1995 apply to facilities that process gas for the purpose of the gas being put into storage, an LNG import or export facility, a gas interconnector or a distribution system pipeline. Ofgem, the regulator responsible for downstream gas and electricity markets, enforces these provisions.

Exemption from the application of third-party access rights may be granted in special circumstances and is only available in relation to interconnectors, LNG facilities and gas storage facilities. In Great Britain, Ofgem has the power to grant such exemptions but any grant remains subject to EU approval. In deciding whether to allow an exemption, Ofgem will consider the participants' market shares and any concerns over capacity-hoarding.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

Parties are free to agree the terms upon which oil or natural gas is to be transported. However, if a third party is unable to agree satisfactory terms of access with the pipeline owner (including the applicable tariff), the third party can make an application to the OGA to require access to be granted. Please refer to question 6.6 above for further details.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

The Gas Act establishes the regulatory framework for the downstream

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gas market in Great Britain. The Office of Gas and Electricity Markets ("**Ofgem**") is the gas and electricity markets regulator. It operates under the direction and governance of the Gas and Electricity Markets Authority ("**GEMA**"). Ofgem is responsible for the regulation of the gas market in England, Scotland and Wales. The regulatory regime is founded on a licensing system, which provides that certain key activities cannot be undertaken without a licence, or, in some instances, an exemption from the requirement to hold a licence. The Gas Act makes it an offence (punishable by a fine) for a person to engage in the relevant activities without a licence or an exemption.

The five types of gas licence are:

- **Gas Transporter Licence** – authorising the licensee (a gas pipeline operator, "**Gas Transporter**") to convey gas through pipelines to any premises within an area specified by the licence (such area may be held by the Gas Transporter or extend to pipelines operated by another Gas Transporter). The Gas Act imposes a duty on Gas Transporters to, amongst other things, maintain an efficient and economical pipeline system and facilitate competition in the supply of gas.
- **Gas Interconnector Licence** – authorising the licensee to convey gas into, or through, a gas interconnector or to make such an interconnector available for use for the conveyance of gas.
- **Gas Shipper Licence** – authorising the licensee (a gas wholesaler, "**Gas Shipper**") to contract with a Gas Transporter for gas to be introduced into, conveyed by means of, or taken out of a pipeline system operated by that Gas Transporter either generally or for purposes connected with the supply of gas to any premises specified in the licence. Gas Shippers purchase natural gas from upstream producers or other traders or wholesalers and enter into contractual arrangements with Gas Transporters for the natural gas to be transported to the customers of Gas Suppliers. Each Gas Transporter is required to have in place a network code setting out the applicable transportation arrangements to enable Gas Shippers to use the Gas Transporter's pipeline. The individual Gas Transporter's network code will incorporate the Uniform Network Code ("**UNC**"), which sets out the detailed arrangements in relation to the supply and transportation of natural gas through the NTS. Gas Shippers agree to be bound by the UNC by entering into, or acceding to, a framework agreement with a Gas Transporter.
- **Gas Supplier Licence** – authorising the licensee (a gas retailer, "**Gas Supplier**") to supply gas to any domestic or non-domestic premises through pipelines. Customers benefit from the competition that exists between Gas Suppliers as a result of the UK having an open gas supply market.
- **Smart Meter Communication Licence** – as part of a new regulatory regime for the roll-out of smart metering in GB, the Gas Act 1986 has been amended to provide for the licensing of a person providing a smart meter communication service. The licence is also referred to as a Data and Communications Company ("**DCC**") Licence. In September 2013, Smart DCC Ltd was granted the DCC Licence by DECC. The DCC Licensee will manage the smart metering service on behalf of its users and will contract with, and manage, the data and communications service providers. The Smart Energy Code ("**SEC**") is a new industry code which is created and comes into force under the DCC Licence. It is a multiparty contract which sets out the terms for the provision of the DCC's smart meter communications service and specifies other provisions to govern the end-to-end management of smart metering. The DCC, energy suppliers and network operators are required by conditions of their licences to become a party to the SEC and comply with its provisions. Other bodies who wish to use the DCC's services, such as energy efficiency and energy service companies, must accede to the Code to do so.

All gas licences are subject to standard conditions imposed by the Secretary of State, but Ofgem is authorised to amend or modify these conditions as appropriate.

To facilitate effective competition, the Gas Act de-links the transportation, shipping and supply of natural gas and prohibits a person from holding a Gas Transporter Licence or a Gas Interconnector Licence with any other type of gas licence.

The regulator, Ofgem, is responsible for granting licences. In granting licences, Ofgem takes into account the technical and financial suitability of applicants, their ability to comply with relevant health and safety standards, and their ability to discharge their licence obligations.

Industry codes provide another important layer of regulation. This is achieved through licence conditions which require licensees to maintain or become parties to the relevant industry codes. The most important of these is the Uniform Network Code, mentioned above.

National Grid is the owner and operator of the high pressure NTS. There are eight GDNs which each cover a separate geographical region of Britain. In addition, there are a number of smaller networks owned and operated by Independent Gas Transporters: most but not all of which have been built to serve new housing. Four of the GDNs are owned by SGN, Northern Gas Networks and Wales & West Utilities. The other four GDNs were, until recently, fully owned by NGG, but in March 2017 NGG completed the sale of a 61 per cent equity interest in National Grid Gas Distribution (the company that owns the GDNs) to a consortium of long-term infrastructure investors, and the company was re-named Cadent Gas Limited. The entire UK network comprises 6,600 km of high-pressure national and regional transmission systems and around 275,000 km of lower pressure local distribution systems. The owners and operators of the NTS and the GDNs are each required to hold a Gas Transporter Licence, as discussed above.

Northern Ireland operates its own gas market, under the oversight of the devolved Government in Northern Ireland, and its own regulator, the Utility Regulator.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

As mentioned in question 7.1 above, a Gas Transporter Licence issued under the Gas Act is a key authorisation required for the operation of a distribution network. In addition, there are a large number of planning, environmental and health and safety requirements that apply during the construction of a distribution network, as well as during the ongoing operation of the network. For example, the Gas Safety (Management) Regulations 1996 require each Gas Transporter to prepare a Safety Case document that sets out in detail the arrangements in place in relation to issues such as the management of gas escapes.

7.3 How is access to the natural gas distribution network organised?

The Gas Act imposes a general duty on gas transporters (i.e. network operators) to provide access. The Act states that a gas transporter must, in relation to its authorised area: develop and maintain an efficient and economical pipeline system for the conveyance of gas; and comply, so far as it is economical to do so, with any reasonable requests by third parties to connect to that system, and convey gas by means of that system to any premises; or to connect to that system a pipeline system operated by another authorised gas transporter.

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Specific duties to facilitate this access are dealt with in more detail in the terms of the licence conditions set out in the Gas Transporter Licence held by operators of gas transmission and distribution networks. In particular, network operators are required to maintain charging methodologies, relating to transportation (use of system) charges as well as connection charges, which set out the principles of and methods used to calculate charges. Any charges must be cost-reflective, facilitate competition, and reflect developments in gas distribution. The licence conditions expressly state that access to the system must be granted in accordance with the provisions of the Gas Act and the Third European Gas Directive. Under the Gas Act licence-exempt network, operators are also required to grant third-party access.

All Gas Shippers must accede to the UNC, which defines the rights and responsibilities for users of the GB gas transportation system (the NTS and GDNs), and provides for all system users to have equal access to transportation services. Participation in the market under the UNC is through forward-nominated trades with counter-parties and physical or non-physical within-day trading. Both balancing and charging take place on a daily basis. In addition to the balancing requirements, the UNC also deals with a number of other issues, including entry and exit requirements, emergencies and storage.

If parties are unable to agree upon access arrangements, an application can be made to Ofgem to exercise its powers in relation to third-party access (see question 7.4 below).

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

As mentioned in question 7.3 above, the Gas Act requires every Gas Transporter to comply with any reasonable request for it to convey gas by means of its pipeline system to any premises, provided it would not prejudice the efficient operation of the Gas Transporter's pipeline system.

The Third European Gas Directive also requires that non-discriminatory third-party access to distribution and transmission pipeline systems be provided, and that the gas regulator have the power to determine any disputes arising in relation to such access. In compliance with the requirements of the Third European Gas Directive, the Gas Act provides for Ofgem to determine any such access disputes (so-called "**Article 41 disputes**"). Disputes about connections and use of system can also arise in relation to specific obligations of the transporter under the terms of their Gas Transporter Licence. Ofgem has a wide range of dispute resolution powers that may be applicable in this context, and is able to determine disputes between system operators and Gas Shippers, as well as between system operators and gas users wishing to connect their premises to the system.

An application to Ofgem could involve a request by the applicant that the relevant system operator increase the capacity of the relevant pipeline through modification of associated works and apparatus, or for the installation into any such pipeline of an interconnection point. If Ofgem determines the dispute in favour of the applicant, by making an order requiring access to be granted, the applicant will generally be obliged to pay for the reasonable cost of the relevant work, as determined by Ofgem.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Gas Transporters charge connection and use of system charges derived by reference to price control formulae and subject to price control by Ofgem. From 1 April 2013, Ofgem introduced a new performance-based model to set price controls, referred to as "**RIIO**" (which stands for "**Revenue set to deliver strong Incentives, Innovation and Outputs**"). Building upon the previous Retail Price Index formula (which used the rate of inflation as a benchmark and subtracts an efficiency factor to provide the allowed changes in network prices), the RIIO model, among other features, uses rewards and penalties related to output delivery, extends the price control period to eight years from the previous five and introduces an innovation stimulus package.

RIIO-GD1 is the first gas distribution price control review to use the RIIO model. The RIIO-GD1 price control sets out the outputs that the eight GDNs need to deliver for their consumers and the associated revenues they are allowed to collect for the eight-year period from 1 April 2013 until 31 March 2021. An equivalent price control review – RIIO-T1 – applies to gas transmission for the eight-year period from 1 April 2013 until 31 March 2021.

Under the terms of the Gas Transporter's Licence, a Gas Transporter must conduct its business to ensure that neither it nor any of its related companies obtains any unfair commercial advantage.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

Please see the requirements and restrictions referred to under question 7.1 above.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Trading takes place at a number of points in the gas supply chain. In the mid-1990s, gas was principally traded from producers to Gas Shippers at the onshore entry points into the NTS, known as the "**beach**". Beach trades are usually contractually documented under gas supply/sale agreements.

More recently, gas is predominantly traded after leaving the beach and entering the NTS, at the National Balancing Point ("**NBP**"): a virtual location created by the UNC. Over-the-counter NBP trades are principally made on the terms of the "**NBP '97**" contract (which was updated and reissued in 2015 as "**NBP 2015**"), although ISDA contracts (with a gas annex attached) are also used. To effect a trade, a party makes a nomination via Gemini (a dedicated computer application operated on behalf of NGG), setting out the volumes of gas that it contracts to deliver or offtake from another party, the date, and the entry or exit point to the NBP, unless the trade is solely within the NBP.

The NBP is also where NGG, the Transmission System Operator, balances the NTS on a daily basis. The UNC moved balancing from a monthly to a daily regime when it was introduced in 1996 (then called the "**Network Code**"), placing an obligation on NGG to physically balance the NTS each day. NGG passes on the costs of any shortfall to the Gas Shippers: a delivery shortfall by a Gas Shipper will require the Gas Shipper to pay a punitive charge of the System Marginal Buy Price (which may be the highest price traded by NGG that day). Conversely, a Gas Shipper long of gas will be cashed out at the System Marginal Sell Price (which may be the lowest price traded by NGG that day).

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Gas can also be physically traded at the NBP via an anonymous, screen-based, within-day gas market: the on-the-day commodity market ("**OCM**"). This allows Gas Shippers to fine-tune their daily positions and allows NGG to purchase and sell gas in order to balance the NTS. The OCM is operated by an independent market operator, ICE Endex.

Any party that wishes to arrange for the conveyance of gas through the NTS must hold a gas shipper licence. However, in October 2012, Ofgem confirmed that parties not involved in the physical conveyance of gas through the network, but who simply trade gas as a commodity at the NBP do not require a gas shipper licence. The party will also need to accede to the Uniform Network Code, irrespective of whether it is involved in the physical conveyance of gas through the network or not.

Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency ("**REMIT**") came into force on 28 December 2011. REMIT, being an EU regulation, applies directly to parties engaging in gas trading in the UK, imposing prohibitions on insider trading, market manipulation and an obligation to publish inside information and to report suspicious transactions. Ofgem, the gas and electricity markets regulator, has been given the powers to enforce REMIT in GB. The Electricity and Gas (Market Integrity and Transparency) (Enforcement etc.) Regulations 2013, which entered into force on 29 June 2013, give Ofgem the necessary powers to enforce the REMIT provisions relating to the prohibition on insider trading and market manipulation, the obligation to publish inside information and to report suspicious transactions. Under the Regulations, Ofgem has investigative powers, and can impose unlimited penalties. Under REMIT, gas market participants will also have to register with Ofgem and report to ACER (the Agency for the Cooperation of Energy Regulators) transactions covered by REMIT. For the purposes of the REMIT transaction reporting regime, market participants have to register with Ofgem and report to the Agency for the Cooperation of Energy Regulators transactions covered by REMIT. A market participant is defined in REMIT as any person, including transmission system operators, who enters into transactions, including the placing of orders to trade, in one or more wholesale energy markets. REMIT registration in Great Britain opened on 1 December 2014 and the REMIT transaction reporting obligations commenced on the following dates:

- for standard contracts (i.e. those traded on an organised market place) – reportable from 7 October 2015; and
- for non-standard contracts – reportable from 7 April 2016.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

There is no obligation to trade only bundled products. Instead, gas as a wholesale commodity, entry and exit capacity on the NTS and balancing services can all be traded independently.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

There are no LNG liquefaction or export facilities in the UK, and in view of the UK being a net importer of natural gas, no such facilities are planned. However, there are a number of existing LNG import sites currently operating in the UK (detailed in question 1.1 above).

9.2 What governmental authorisations are required to construct and operate LNG facilities?

The construction and operation of LNG facilities must comply with the relevant environmental, planning and health and safety requirements referred to in questions 3.11 and 3.13 above. There are no specific UK Government authorisations required to construct and operate LNG facilities, other than the offshore unloading licence discussed in question 3.13 above. The offshore unloading licence, introduced under the Energy Act 2008, is intended to facilitate the future development of any offshore fixed or floating LNG receiving terminals.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The Third European Gas Directive provides that terms and conditions for the provision of such services by LNG system operators, including rules and tariffs, must be established in a non-discriminatory and cost-reflective way and must be published (see question 3.13 above for further details).

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

The Third European Gas Directive requires EU Member States to implement a regime of third-party access to LNG facilities, which in the UK is implemented in the Gas Act. The EU Gas Regulation, which forms part of the EU's Third Energy Package together with the Gas Directive, also applies directly.

Unlike the negotiated third-party access regime that applies to gas storage facilities, which is discussed in question 3.13 above, the regime that applies to LNG facilities is regulated third-party access. This means that access is based on published tariffs and/or other terms and obligations which have been approved by the regulator.

Specifically, under the Gas Act, the owner of an LNG facility must publish the main commercial conditions relating to the grant to another person of a right to have gas treated at the facility. Any charges for using the facility, or the method for calculating such charges, must be approved by Ofgem. The conditions of access must not discriminate against any applicants. Any third party that wants to have gas treated at the LNG facility has the right to apply to the owner. If the owner refuses the application, then that party can make an application to Ofgem for the grant of rights to use the facility.

The TPA exemptions regime that applies to LNG facilities is similar to that described in relation to storage facilities in question 3.13 above.

Each of South Hook LNG, Dragon LNG and Grain LNG has been granted an exemption by Ofgem from the application of third-party access rights under the Gas Act, which exemptions have been approved by the European Commission (which possesses the right to veto the granting of such an exemption). Each of these exemptions were granted on the condition that the access arrangements in respect of the LNG facilities contained capacity management and anti-hoarding measures. At present there are no LNG facilities in Great Britain which are subject to rTPA.

Ofgem retains the right to revoke an exemption if market circumstances change.

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10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream oil sector, unlike gas, is not subject to the oversight of a market regulator like Ofgem. Nonetheless, there are some specific regulatory requirements that apply, mainly relating to energy security and environment and health and safety issues.

As a Member State of the EU and the IEA, the UK is required to implement certain emergency oil stocking obligations. The UK meets its international obligations by directing companies to hold stocks. Section 6 of the Energy Act 1976 allows the Secretary of State for Business, Energy and Industrial Strategy to give directions to businesses producing, supplying or using petroleum products within the UK market, requiring them to hold minimum levels of oil stocks. Currently, the level of the obligation is set at 67.5 days' supplies for refiners and 58 days' supplies for non-refiners. The Oil Stocking Order 2012 sets out the type, location and uses of stocks of crude liquid petroleum and petroleum products that may be counted towards an obligated person's stocks. In 2009, the Court of Appeal dismissed a legal challenge, by an oil importing company, to the way the Secretary of State has implemented the compulsory oil stocking obligations in the UK (*R (Mabanaft) v Secretary of State for Energy and Climate Change* [2009] EWCA Civ 224).

The Renewable Transport Fuel Obligation ("**RTFO**"), established under the Renewable Transport Fuel Obligations Order 2007, imposes an obligation on fuel suppliers to ensure that sustainable renewable fuel makes up a percentage of the volume of fuel they supply for road transport. Initially the RTFO only covered suppliers of fuel for use in road vehicles. The RTFO Order was amended for fuel supplied from 15 April 2013 to cover suppliers of fuel for use in non-road mobile machinery (including inland waterway vessels which do not normally operate at sea), agricultural and forestry tractors, and recreational craft that do not normally operate at sea. For the year 2013/2014 and subsequent years, the level of the obligation has been set at 4.9870 per cent. In 2017, it was decided that the obligation level will increase to 9.75 per cent in 2020. For each litre of biofuel (or kilogram of biogas) supplied, a Renewable Transport Fuel Certificate ("**RTFC**") is issued. Obligated suppliers meet their obligation by redeeming RTFCs or by paying a fixed sum for each litre of fuel for which they wish to "buy-out" of their obligation. The effect of the RTFO is to create a subsidy and market for biofuels, which are typically more expensive than petroleum products. In practice, suppliers blend biofuels with conventional oil products to comply with the RTFO.

There are also a large number of environmental and health and safety requirements that apply to facilities that process or store oil and oil products. The most significant of these are the Control of Major Accident Hazards Regulations 1999 ("**COMAH**"). These regulations require relevant facilities to take all necessary measures with regard to the containment of hazardous liquids, to prevent major accidents and limit their consequences to persons and the environment. The COMAH regime was the subject of significant review after a serious explosion at the Buncefield Oil Storage Depot in 2005, resulting in more stringent requirements, set out in a new "Containment Policy" introduced in 2008. Operators of refining plants will normally require an environmental permit issued pursuant to the Environmental Permitting (England and Wales) Regulations 2016, among other environmental permits and consents.

Manufacturers or importers of oil products are also required to comply with the EU's REACH Regulation, which requires registration of all the chemical products circulated in the EU market by EU-based manufacturers and importers, as well as non-EU companies exporting their products to the EU.

In October 2017, in what is a significant development for the downstream oil industry, the Government published for consultation a suite of new regulatory resilience measures, including new reporting requirements, designed to protect against fuel supply disruptions.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

The price of crude oil that is bought and sold around the globe is directly or indirectly determined by reference to crude oil benchmarks, also known as oil markers. There are three primary benchmarks: West Texas Intermediate ("**WTI**"); Brent Blend; and Dubai. Other well-known blends include the Opec Reference Basket, Tapis Crude which is traded in Singapore, Bonny Light used in Nigeria and Mexico's Isthmus.

Price formation in respect of the most widely used oil markers, WTI and Brent Blend, happens on futures exchanges, respectively the New York Mercantile Exchange ("**NYMEX**") and Intercontinental Exchange ("**ICE**"). The price formation mechanism on the exchanges is, in turn, correlated with the physical availability of the crude oil in the reference market. The physical reference market for Brent Blend is crude oil that is produced in the North Sea.

The price for crude oil to be delivered on a forward basis is often determined by reference to the relevant futures price. Most oil cargoes and consignments generally that happen in Europe, Africa and the Middle East reference the Brent ICE futures contract.

Apart from offering a benchmark price for physical consignments of oil, future contracts also provide a tool to eliminate the risk relating to price fluctuations in the future. Most crude oil is traded on a forward basis. Where a price for oil to be delivered in the future is fixed at the outset the seller must seek protection against a decrease in price. The buyer will have the opposite need. This makes forward sellers and buyers natural holders of "short" and "long" positions on the futures market.

However, the futures market is not purely made up of entities that have an interest in physical oil. A large part of the market is speculative in nature. Namely, it consists of futures positions taken by those who wish to have exposure to the price of crude oil. Furthermore, the futures contracts referred to above provide for reference prices for so-called over-the-counter derivatives that are entered into bilaterally either for hedging purposes of for speculative purposes.

The combination of futures trading and over-the-counter derivatives is commonly referred to as "paper trading" as opposed to the physical trading of crude oil. A much larger number of paper trades of crude oil take place than the physical crude oil trades that inform the relevant benchmark price.

Participants in both the physical and paper crude oil markets include producers, refiners, independent trading houses and, increasingly, the commodity trading arms of investment banks.

Physical trading of crude oil remains largely an unregulated activity. It is subject to rules for the handling and transportation of hazardous and polluting materials, as discussed in question 10.1 above. Crude oil paper trading comes within the scope of new rules on derivatives trading, most notably the Markets in Financial Instruments Directive (MiFID) and MiFID II in the EU context.

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11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

As far as UK activities are concerned, competition law can be enforced by:

- the European Commission, which is the principal EU institution responsible for enforcing the competition provisions contained in the Treaty on the Functioning of the European Union ("**TFEU**") across the European Union; and/or
- the UK national competition authority, the Competition and Markets Authority ("**CMA**"), and the sectoral regulators with concurrent competition law enforcement powers, of which the most relevant to the natural gas sector is Ofgem, the gas and electricity markets regulator. Note that Ofgem has no role to play in the oil market.

The enforcement powers of the European Commission in this context are likely to be affected by Brexit, but it is not yet clear exactly what the position will be. For the purposes of this chapter, we have therefore focused on the position at the time of writing.

The Enterprise and Regulatory Reform Act 2013 ("**ERR Act**") introduced significant changes to the institutional structure of the UK competition law regime, with the creation of the CMA to replace its predecessors, the Office of Fair Trading and the Competition Commission, from 1 April 2014.

With regard to the interaction between the European Commission and the national competition authorities, the European Commission has issued a Notice on Cooperation within the Network of Competition Authorities (2004/C101/03). The Commission indicates in this Notice (paragraph 14) that it is particularly well placed to deal with a case where the agreements or practices have effects on competition in more than three EU Member States. However, it should be noted that the European Commission has conducted a number of investigations regarding agreements or conduct involving ostensibly national gas markets; for example, its investigation into RWE's ownership of the German gas transmission network.

As regards the interaction of the UK national competition authorities, pursuant to the Competition Act 1998 (Concurrency) Regulations 2014 and the Gas Act 1986, Ofgem (which is responsible for the regulation of the energy sector in Great Britain) and the Director General of Gas for Northern Ireland (within the Northern Ireland Authority for Utility Regulation) have concurrent powers with the CMA to investigate suspected anti-competitive activity and take action for breaches of competition law in the gas sector. In particular, the CMA and Ofgem have concurrent powers to apply and enforce Articles 101 and 102 of the TFEU as well as Chapter I and II of the Competition Act 1998 (which prohibit anti-competitive agreements and abuse of a dominant position – see further question 11.2 below).

Significantly, the ERR Act gives the Secretary of State the power to make an order to remove Ofgem's concurrent powers, if the Secretary of State considers that it is appropriate to do so for the purpose of promoting competition. This provision was included because there was a feeling in some quarters that Ofgem did not have a strong track-record in using its concurrent competition law enforcement powers. In addition, the Government strengthened the primacy of general competition law, to try to increase the use by sectoral regulators of their concurrent enforcement powers rather than sector-specific regulatory powers to promote competition within their relevant industries. Ofgem is now required to first consider whether it would be more appropriate to take action under the Competition Act 1998 before exercising its regulatory powers. The CMA and Ofgem (as well as other sectoral regulators) are also required to consult more and share information, with the CMA being obliged to report annually on the use of concurrent competition powers across all regulated industries.

The interaction between Ofgem and the CMA is further governed by a Memorandum of Understanding dated 18 January 2016 (replacing an earlier MoU) between GEMA (for which Ofgem is the supporting administrative body) and the CMA, which deals with matters of general co-operation between the two regulators, as well as the principles to be applied to case allocation. The MoU provides that the basis for the determination of jurisdiction will be the general principle of which of them is better placed to exercise those powers, having regard to the factors set out in the CMA's guidance on concurrent application of competition law to regulated industries.

In addition, Ofgem or, in cases that raise public interest considerations, the Secretary of State, can refer a market in the natural gas sector to the CMA for an in-depth market investigation under the Enterprise Act 2002, if there are reasonable grounds for suspecting that any feature, or combination of features, of that market prevents, restricts or distorts competition. The CMA has considerable remedial powers if it concludes that a market operates such that there is an adverse effect on competition, including in extreme cases requiring divestments (as the CMA's predecessor, the Competition Commission, did in its 2009 report in its market investigation into BAA plc).

In June 2014, Ofgem used these powers to refer the UK energy market to the CMA for an in-depth market investigation. The referral followed a competition assessment requested by the Government in October 2013, which was completed by Ofgem jointly with the Office of Fair Trading and the CMA. The market investigation considered whether there are any features of the UK energy market which prevent, restrict or distort competition, and if so, what action is required to remedy, prevent or mitigate those effects. On 24 June 2016, the CMA published its final report, two years after the market investigation reference was first made. While a detailed discussion of all the complex issues addressed by the CMA is outside the scope of this chapter, it is pertinent to note that the CMA found that competition in the wholesale gas markets works well, and the presence of vertically integrated firms does not have a detrimental impact on competition. The CMA did, however, conclude that the current system of gas settlement leads to an inefficient allocation of costs to parties and creates scope for gaming, which reduces the efficiency and, therefore, the competitiveness of domestic retail gas supply. Some reforms to the settlement process were therefore implemented. The CMA also identified a range of problems hindering competition in the retail market, including the extent of consumer engagement, as well as certain shortcomings in regulation (for example, interventions designed to simplify prices, which the CMA found were not having the desired effect of increasing engagement, and limited discounting and reduced competition). A wide range of remedies to address the problems identified in the retail market have been (or are being) implemented – including, for example, a price cap on the prices offered to prepayment meter customers during a transitional period (2017–2020).

The possibility of introducing a wider price cap on retail energy prices was rejected by the CMA during its market investigation, but in October 2017 the Government separately proposed legislation (the Tariff Cap Bill) to introduce a cap on the gas and electricity tariffs charged to domestic customers on all standard variable and default rates. This would be achieved by requiring Ofgem to modify the supply licence conditions of suppliers. As at October 2017, the Bill is being debated in Parliament, but it is intended that the tariff cap will be in place from

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winter 2018/19 or sooner until the end of 2020 (with the possibility that this period could be further extended). Pending the implementation of the tariff cap, Ofgem has announced that it is extending the existing prepayment meter tariff cap to other vulnerable domestic customers.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

As indicated above, both EU and UK competition law is currently applicable in the UK (pending Brexit) and both may apply to the same conduct. In summary, EU competition law applies where the agreements, business practices or behaviour concerned may affect trade between EU Member States – a concept which is broadly defined. UK competition law will apply where there may be an effect on trade within the UK.

Anti-competitive agreements

Article 101 of the TFEU and Chapter I of the Competition Act 1998 prohibit agreements and concerted practices which, by object or effect, may prevent, restrict or distort competition. These laws apply not only to formal written agreements, but also to oral "gentlemen's agreements" and can also apply to tacit understandings between businesses. Under both EU and UK competition law, the prohibition on anti-competitive agreements only applies where there is an appreciable prevention, restriction or distortion of competition.

Some agreements, such as price-fixing or market-sharing cartels or (generally) resale price maintenance obligations, are considered to be anti-competitive by their nature, regardless of their actual effects (known as "object restrictions"); others, such as exclusive purchasing and supply obligations, will only infringe the law where anti-competitive effects can be shown.

Agreements and concerted practices which *prima facie* prevent, restrict or distort competition may nevertheless benefit from an exemption where, broadly speaking, the anti-competitive effects are outweighed by pro-competitive benefits for consumers (in practice, exemptions will not generally be available in cases involving "object restrictions").

It should be noted that in the UK, individuals involved in cartel activity (defined as agreements relating to price-fixing, market/customer sharing, output limitation or bid-rigging) may be subject to criminal prosecution for the so-called "criminal cartel offence" under the Enterprise Act 2002. If found guilty, an individual may face an unlimited fine and/or up to five years' imprisonment. The scope of this offence was significantly widened with effect from 1 April 2014, by the removal of the previous requirement that the individual in question must be shown to have acted "dishonestly".

Abuse of dominant position

Article 102 of the TFEU and Chapter II of the Competition Act 1998 prohibit conduct by one or more undertakings which amounts to the abuse of a dominant position. The essence of dominance is the ability to behave independently of competitive pressures, i.e. the behaviour of customers, suppliers and competitors. An undertaking may have a sole dominant position or a collectively dominant position together with other competitors, although the latter is relatively rare. EU and UK competition law do not provide statutory market share thresholds for defining dominance but, as a general rule, dominance is unlikely to be a concern where market shares are less than 40 per cent; however, there is a rebuttable presumption of dominance where market shares are persistently 50 per cent or more. Factors such as the size and number of competitors and customers, the ease of setting up a new business in competition, and the strength of customers ("buyer power") are all relevant to the assessment of dominance.

Holding a dominant position in a particular market is not prohibited under either EU or UK competition law; what is prohibited is the *abuse* of that dominant position. Examples of potential abuse of a dominant position include charging unfair prices (which could be excessively high for consumers or excessively low in order to drive a competitor out of business) or imposing other unfair trading conditions, refusing to supply an existing customer without good reason, limiting production, markets or technical development, or applying different conditions to similar transactions with different parties.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

Both the European Commission (under EU Regulation 1/2003) and the CMA and Ofgem (under the Competition Act 1998) have a broad range of powers to apply and enforce Articles 101 and 102 of the TFEU (as well as, for the CMA and Ofgem, the Chapter I and II prohibitions under the Competition Act 1998). In short, these powers include the ability:

- to investigate suspected infringements, including requesting information and documents, interviewing individuals and conducting unannounced "dawn raids";
- to impose interim measures during the investigation (in practice, this happens very rarely);
- to give directions to bring an infringement to an end;
- to accept binding commitments which address competition concerns; and
- to impose financial penalties on undertakings of up to 10 per cent of an undertaking's group worldwide turnover in the business year preceding the date of the decision. Such fines can run into the tens and hundreds of millions of pounds (the highest individual EU fine so far is EUR 2.42 billion).

In addition to these powers, the Enterprise Act 2002 gives the CMA the power to bring a prosecution for the criminal cartel offence (see question 11.2 above for further information). Finally, pursuant to the Company Directors Disqualification Act 1986 (as amended by the Enterprise Act 2002), the CMA and/or Ofgem may apply to the court for an order disqualifying an individual from acting as a director of a company for up to 15 years. An order will be granted where the individual has been the director of a company involved in a breach of UK or EU competition law and the court decides that the director's conduct makes him or her unfit to be concerned in the management of a company.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Mergers and acquisitions involving UK natural gas businesses may be subject to either:

- the EU Merger Regulation ("**EUMR**"); or
- the UK merger control regime contained in the Enterprise Act 2002.

EUMR

A transaction will be subject to the EUMR where it involves an acquisition of control (as defined under the EUMR) and the turnover

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of the parties involved (the "**undertakings concerned**") meets the relevant EUMR turnover thresholds. The first set of thresholds is as follows:

- the combined aggregate worldwide turnover of all the undertakings concerned is more than EUR 5 billion; and
- the aggregated EU-wide turnover of each of at least two of the undertakings concerned is more than EUR 250 million,

unless each of the undertakings concerned achieves more than two-thirds of its aggregate EU-wide turnover within one and the same EU Member State.

A further supplementary (and more complicated) set of thresholds was introduced in 1998 and is designed to catch mergers where the parties involved have sizeable turnover in at least three separate EU Member States.

If a transaction is caught by the EUMR, it must be notified to the European Commission and completion suspended until clearance has been obtained. The substantive test that the European Commission applies in assessing the merger is whether the transaction significantly impedes effective competition in the EU or in a substantial part of it, in particular as a result of the creation or strengthening of a dominant position.

The European Commission applies a two-phase procedure. It will carry out its initial assessment during Phase I, which lasts 25 working days from submission of a complete notification (extendable by a further 10 working days where the parties offer commitments or in certain other circumstances). At the end of Phase I, the European Commission may decide to clear the merger (with or without commitments) or initiate an in-depth Phase II investigation, which can take up to a further 90 working days and can be extended further up to 125 working days (depending on whether the parties offer commitments and request or accept an extension). It should also be noted that, prior to notification, the European Commission will expect the parties to engage in pre-notification discussions, including submitting drafts of the notification. Even in straightforward cases, pre-notification discussions can take four to six weeks. In cases raising competition concerns or novel issues, pre-notification discussions can take several months.

If the EUMR applies to a transaction, it will in principle do so to the exclusion of EU Member States' national merger control regimes. The main caveat to this is that there are provisions in the EUMR that allow for the referral of transactions back to national competition authorities in certain circumstances, in particular where the transaction raises particular competition concerns in one Member State.

UK Merger Control

A merger that does not qualify for investigation under the EUMR is subject to the merger control provisions of the Enterprise Act 2002 where the relevant jurisdictional thresholds are met, namely: (i) the target has annual turnover in the UK of more than £70 million; or (ii) as a result of the merger, the merged entity will have a share of supply in the UK (or a substantial part of the UK) of goods and services of at least 25 per cent and that share of supply is increased as a result of the merger.

It should be noted that the UK merger control regime applies not only to acquisitions of a controlling interest but also to changes of control at a much lower level, thus the acquisition of what is known as "material influence" will potentially trigger the application of the UK merger control regime. A shareholding of around 15 per cent has, in certain circumstances, been considered sufficient to constitute "material influence"; for example, where a shareholder in practice has the ability to block special resolutions because of the spread of other shareholdings and general patterns of attendance at shareholders' meetings. Moving up through the levels of control, e.g. from material influence to a controlling interest, will also potentially trigger the application of the regime.

The substantive test applied in UK merger control is whether the transaction may be expected to result in a substantial lessening of competition in any market or markets in the UK. In practice, this is very similar to the EU test.

Merger control review in the UK is a two-stage process. At the first stage, known as Phase 1, the CMA undertakes an initial review of the transaction and, where it has no material competition concerns about the merger, it will issue a clearance decision. Where there are material concerns about the impact of the merger on competition, the CMA may either accept undertakings from the parties to address those concerns, or it may refer the merger to an Inquiry Group for an in-depth Phase 2 review. At that stage, the CMA may clear the merger unconditionally, may clear the merger subject to conditions, or may prohibit the merger outright. The CMA has wide powers to request information from the parties during the review process, and will also consult interested third parties (such as customers, suppliers and competitors) for their views when assessing the likely impact of a merger.

It is important to note that, unlike the EU merger regime, the UK merger control regime does not impose any mandatory notification requirements or waiting periods. This means that parties are free to complete their transactions without notifying them to the CMA or, in the event that the transaction is notified, without waiting for a clearance decision prior to completion of the transaction. However, the fact that a merger is not notified by the parties does not mean that it will escape scrutiny under the UK merger control regime. The CMA has the power to review mergers whether or not they are notified, and has a dedicated Mergers Intelligence Officer responsible for monitoring merger activity in the UK. As a member of the European Competition Network, the CMA may also learn about a merger through liaison with other national competition authorities who have received a (very often mandatory) notification of the merger in question. Furthermore, the CMA may impose "initial enforcement orders" (often referred to as "hold separate" orders) to prevent any (further) integration of the merging parties pending the outcome of the CMA's investigation. In practice, hold separate orders are imposed on substantially all completed mergers at the earliest opportunity in Phase 1. Further, whilst the CMA is not able to stop formal legal completion of a transaction, it can impose a hold separate order in respect of an anticipated merger, which prevents any integration steps being taken either before or after completion. This power is believed to have been used in at least one case to date. Finally, the CMA can order the reversal of any integration steps that may already have been taken. These powers must be taken into account in considering whether to proceed with the merger without notification and/or clearance.

The Enterprise Act 2002 also allows the Secretary of State to intervene in relation to mergers which raise public interest considerations. The details of the procedure followed in such cases are beyond the scope of this publication, but further information can be found in the UK chapter of *The International Comparative Legal Guide to: Merger Control 2018*.

The Role of Ofgem in Mergers

Mergers in the gas sector are reviewed under the EUMR or the Enterprise Act 2002 in the usual way, but where the transaction is subject to UK merger control, Ofgem will provide its views to the CMA at Phase 1 and, where a reference is made, Phase 2, on the impact of the merger and whether it may be expected to result in a substantial lessening of competition, given its specialist knowledge of market conditions in the sector. However, the ultimate decision rests with the CMA.

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Ofgem may provide its views to the European Commission on mergers involving UK energy businesses which are subject to the EUMR (as it did in relation to the 2008 merger between EDF and British Energy).

It should be noted that, separately from the merger control assessment, Ofgem will always consider whether additional or amended licence conditions should be imposed in light of the merger; for example, the introduction or enhancement of financial ring-fencing provisions. The effect of mergers in regulated sectors will also be taken into account when Ofgem undertakes more in-depth regulatory reviews of regulated markets.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

Limitations on acquisitions are a matter for the competition authority in the UK or the EU (see section 11 above), but are not currently subject to a test based on the nationality of the purchaser (although reforms have recently been proposed which could change this in future – see further below). The only exceptions to this are the provisions of the Third European Gas Directive, which require that a special certification process must be followed where a transmission system owner or transmission system operator is controlled by a person from a non-EU country. As part of the process, Ofgem is required to make an assessment, in consultation with the European Commission, about whether foreign ownership or control of the transmission system would give rise to any risk to security of supply. However, in September 2016, the Government announced that it would be introducing reforms to its approach to the ownership and control of critical infrastructure to ensure that the full implications of foreign ownership are scrutinised for the purposes of national security. While the announcement was made in the context of giving the go-ahead for the Hinkley Point C nuclear power project, it has wider implications for investments in UK infrastructure. As at November 2016 the full details of the reforms have not been published, but will include the introduction of a "national security requirement for continuing Government approval of the ownership and control of critical infrastructure".

However, in October 2017, the Government published proposals for a consultation which would – if implemented – introduce significant changes to its approach to the ownership and control of critical infrastructure, aimed at ensuring that the full implications of foreign ownership are scrutinised for the purposes of national security. These proposals followed on from an earlier announcement made in September 2016, in the context of giving the go-ahead for the Hinkley Point C nuclear power project. The details of the proposals are beyond the scope of this chapter, but they include the possibility of introducing an extended "call-in" power which would broaden the scope for intervention in mergers by the Government where national security concerns arise (which could potentially include some mergers in the energy sector) and/or a mandatory notification regime for foreign investment in certain sectors, including at least parts of the energy sector. The Government's Green Paper indicates that these would be likely to include, for example, gas and electricity interconnectors, long-range gas storage, and Gas Reception Terminals, including LNG that contributes to the security of supply (amongst others – see Annex C to the Green Paper). A consultation is under way at the time of writing, and it is not yet known when, or to what extent, the proposals may be implemented.

In relation to licences for the exploration and development of oil and natural gas resources, the OGA (previously DECC) imposes certain residence requirements on licensees. In order to be a licensee, companies must have a place of business in the UK. If the company is licensee to a licence which covers a producing field, then the company must either be registered at Companies House as a UK company or carry on its business through a fixed place in the UK. Additionally, more practical residence requirements may also be imposed by the OGA on a case-by-case basis if the company is also going to be the operator of the licence to ensure that the operator is able to manage operations properly.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

All regulation in the UK, including competition, environmental, health and safety and other sector-specific concerns is currently constrained by the requirements of EU law. As noted above, this position is likely to change as a consequence of Brexit, but the outcome of EU/UK negotiations is not yet known at the time of writing.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

In the context of the licensing regime under the Petroleum Act, if a dispute relating to a licence arises between the OGA and a licensee, then, pursuant to the Model Clauses, the dispute is required to be referred to arbitration unless the licence expressly provides that the matter under dispute is to be determined, decided, directed, approved or consented to by the OGA. The arbitration is by a single arbitrator appointed by the OGA and the licensee or, if they are not able to agree, by the Lord Chief Justice of England (or the person specified in the Model Clauses if the dispute applies to a licensed area within the Scottish or Northern Irish areas).

The OGA has also been vested with new powers under the Energy Act 2016 to consider disputes between industry participants. The OGA has the power to compel parties to participate in the dispute resolution process, but the OGA's ultimate findings are not legally binding (in contrast to the OGA's decisions in third-party access disputes).

Elsewhere in this chapter, third-party access disputes have been discussed. Depending on whether the dispute relates to downstream or upstream infrastructure, an application for resolution of the dispute can be made to Ofgem or the OGA.

In relation to disputes arising in the context of the downstream gas market, involving the holders of licences issued under the Gas Act and other third parties, the Gas Act sets out various provisions for

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the determination of disputes by Ofgem. In addition, the Gas Act sets out various enforcement powers. If a gas licence holder has a decision made against it by a Government authority pursuant to these enforcement powers, reasons for this decision must be given and any representations or objections which have been made in relation to the dispute must be considered by the authority. If a licence holder desires to question the validity of an order, or appeal a penalty imposed, it may apply to the High Court within 42 days of service of the notice of the decision. Judicial review may also be available where all other avenues for appeal have been exhausted. In particular, judicial review is often the main remedy if a party wishes to challenge Ofgem's decision-making process. The Gas Act sets out a separate regime relating to decisions made by Ofgem in relation to licence condition modifications. Under the relevant provisions of the Gas Act, if Ofgem proposes licence condition modifications (relating to the licences discussed in question 7.1 above), then an appeal against a decision of Ofgem to amend the licence conditions can be made to the CMA by the licence holders, certain materially affected persons or a qualifying body representing them. Market participants may also appeal to the CMA certain decisions by Ofgem relating to industry code modifications.

It should also be mentioned that under the Housing Grants, Construction and Regeneration Act 1996 ("**HGCRA 1996**"), there is a statutory right for parties to a construction contract to refer their disputes to adjudication. Parties cannot contract out of this right. Although oil and gas operations are excluded from the HGCRA 1996, advice should be sought with regard to ancillary activities which involve construction operations.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

The UK ratified the New York Convention on 24 September 1975 and the New York Convention came into force on 23 December 1975. The UK applies the New York Convention only to the recognition and enforcement of awards made in the territory of another contracting state.

ICSID was ratified by the UK on 19 December 1966, and it came into force on 18 January 1967.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

There is no special difficulty in litigating, or seeking to enforce judgments or awards against the UK Government. Public bodies enjoy no immunity against litigation in the UK and are subject to the rule of law on the same basis as individuals and non-state-owned organisations and other entities.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

We are not aware of any instances where foreign corporations or organisations have obtained commercial judgments or awards against UK Government authorities in the context of the oil and natural gas sector. However, the legal system in England and Wales is internationally recognised as being independent and impartial. There is no reason why foreign corporations could not obtain judgments or awards against the UK Government.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Brexit

On 23 June 2016, the UK held a referendum to decide whether the UK should remain a member of the European Union ("**EU**"). The outcome of that referendum is that the UK has decided to terminate its membership of the EU (referred to as "Brexit"). On 29 March 2017, the UK Government served notice under Article 50 of the Treaty on European Union of the UK's intention to withdraw from the EU, formally commencing the process by which the UK will leave the EU. The UK's withdrawal from the EU will occur on 29 March 2019 (which will be two years from the date on which the UK served notice), unless otherwise agreed. The notice was followed by a UK Government White Paper, outlining proposals for a "Great Repeal Bill" (subsequently published in July 2017, under its formal title of the European Union (Withdrawal) Bill) which will have the effect of removing the supremacy of EU law over UK domestic law following the UK's withdrawal from the EU (the "Great Repeal Bill White Paper"). For domestic UK affairs, the Great Repeal Bill White Paper deals with the fact that the removal of EU law from UK law on the day of Brexit would leave large gaps in UK law. It is therefore proposed that existing EU law will be removed but then reimported as domestic UK law (subject to adaptations as required).

It seems likely that the Great Repeal Bill will not have a significant impact on the fundamental structure of the UK upstream oil and gas industry and its governing legal regime, including the licensing system. Leaving aside the prospect of a possible future referendum on Scottish independence, it should be noted that the regulatory framework applying to the upstream industry, and in particular environmental and health and safety regulation, is highly developed independently of EU law, and, at this stage, the industry view is that any impact is likely to be minor. The offshore decommissioning regime mainly stems from international conventions and domestic legislation, and it is therefore expected to be largely unaffected. However, some changes to domestic legislation which implements EU requirements, particularly legislation which refers to EU institutions or processes, are inevitable.

The impact of Brexit on the downstream gas industry will be determined by whether the UK will still participate in the single European gas market.

Shale gas

As mentioned in previous editions of this chapter, the UK Government has been implementing various policy and regulatory initiatives designed to facilitate the development of a shale gas industry in the UK, although to date no production has yet taken place.

Most recently, part of the Conservative Party's election manifesto was a continued commitment to policy support for the shale gas industry, with a number of significant initiatives announced: further reforms to the planning regime; changes to the Government's proposed shale wealth fund so that more money is paid to local communities, including individuals; and the creation of a new shale gas environmental regulator.

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Tax changes relating to decommissioning

In the context of UKCS M&A transactions, decommissioning issues, and particularly the question of with whom the economic burden of decommissioning liabilities should lie, have frequently been a significant challenge. In March 2017, the Government published a formal discussion paper on the case for allowing transfers of tax history between buyers and sellers of late-life assets in the UK offshore oil and gas industry in an effort to maximise tax relief for decommissioning expenses.

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He has a particular focus on the LNG industry and has spent several months on secondment to BG Group working exclusively on a natural gas liquefaction project. He is recognised in *Chambers 2015* for his "*good knowledge of project finance in the oil and gas sector*". He is also cited for having "*a very calming influence when it comes to discussing those big issues*".

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USA

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

In the United States, natural gas is domestically produced and readily available to end-users through an extensive pipeline infrastructure. The growth in shale gas production in recent years is one of the most vitalising forces in US energy markets today. A few years ago, analysts foresaw a growing US reliance on imported sources of natural gas, and significant investments were made in regasification facilities for imports of liquefied natural gas (LNG). Today, LNG terminal operators are re-exporting LNG produced in other countries and temporarily stored in the United States. More significantly, the first LNG produced in the modern era from natural gas reserves located in the lower 48 states of the USA was exported from Cheniere Energy's terminal at Sabine Pass, Louisiana in February of 2016. A number of additional terminal operators, developers and producers have applied or are preparing to apply for permits to export LNG from the United States. As a result, significant investments are being made to re-outfit existing regasification terminals into liquefaction terminals. Additionally, new onshore and offshore terminals are being planned to liquefy domestically produced natural gas for export.

Over the past several years, shale gas development in the US domestic fields has been a "game changer" for the US natural gas market, turning the US into the largest gas producer in the world. The sustainability of this boom depends on the size of the shale gas resource base, the price level required to sustain its development, and whether there are technical or environmental factors that might dampen its development. Beyond those questions, the level of future natural gas production in the US will also depend on the level of domestic consumer demand (the US is the largest consumer of natural gas in the world), which will be shaped by prices, economic growth, and policies affecting fuel choice.

US natural gas proved reserves have increased every year since 1999. Shale gas development has helped to increase total US natural gas reserves by almost 50 per cent over the past decade.

In 2016, the US produced 26.7 trillion cubic feet (Tcf) of dry gas. Domestically, the largest onshore producing fields are located in Texas, Oklahoma, Wyoming, New Mexico, Louisiana, North Dakota and Colorado. Offshore production, primarily in the Gulf of Mexico, also serves a critical role in the US's natural gas sector.

In 2016, the US imported approximately 3,000 billion cubic feet (Bcf) of natural gas, the overwhelming majority of which was imported in gaseous form by pipeline from Canada. There are currently eight facilities in the US capable of importing LNG. However, as indicated above, interest is now focused on developing *export* LNG facilities and, in some cases, re-fitting existing *import* facilities for export. In 2016, natural gas exports amounted to 2,315 Bcf, mostly by pipeline but with increasing amounts being exported by tanker in the form of LNG.

The United States' natural gas transportation network delivers more than 23 Tcf of natural gas to over 70 million customers annually. The network, excluding gathering system operators, is made up of about 1.5 million miles of mainline and other pipelines and includes more than 200 mainline transmission pipeline systems and more than 1,300 local distribution companies (LDCs). Over 300,000 miles of interstate and intrastate transmission pipelines transport natural gas from producing areas to market areas. Construction of new transmission and local distribution pipelines during the last decade surpassed that of any other decade since the 1950s.

Underground natural gas storage provides pipelines, LDCs, producers and shippers with an inventory management tool, seasonal supply backup and access to supplies for balancing. About 125 natural gas storage operators manage roughly 400 underground storage facilities. In August of 2017, the US had a total natural gas underground storage capacity of approximately 9,258 Bcf.

Natural gas is priced and traded at different locations throughout the US. These locations, referred to as 'market hubs', exist across the country and are located at the intersection of major pipeline systems. There are over 30 major market hubs in the US, the best known of which is the Henry Hub, located near Erath, Louisiana. Future contracts for natural gas are traded on the New York Mercantile Exchange (NYMEX). These contracts are based on natural gas for physical delivery at the Henry Hub.

The production and delivery of natural gas in the US is subject to significant regulation from a number of regulatory bodies, including the Federal Energy Regulatory Commission (FERC), the Department of Energy (DOE), the Department of Transportation (DOT) and state regulatory bodies. In brief, under the current regulatory framework, pipelines and LDCs are heavily regulated with respect to the services they provide. Interstate pipeline companies, which can serve only as transporters of natural gas, are regulated by the FERC

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in the rates they charge, the access they offer to their pipelines, and the siting and construction of new pipelines. Similarly, LDCs are regulated by state regulatory bodies, which oversee their rates and services, and procedures for maintaining adequate supplies for their customers. In contrast, natural gas producers and marketers are not heavily regulated. While producers are subject to environmental and conservation controls and are required to obtain the proper authorisations and permits before beginning to drill, particularly on federally owned land, the prices that production and marketing companies charge are a function of competitive markets, subject to the FERC's monitoring for market manipulation and abuse.

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Natural gas provides approximately 33 per cent of the United States' energy supply.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Domestic production provides approximately 91 per cent of the United States' natural gas requirements.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Natural gas exports rose to a record level of 2,315 Bcf in 2016. The vast majority of which is exported by pipeline to Canada and Mexico. However, increasing amounts of domestic natural gas production are being exported in the form of LNG.

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

The oil sector in the US has been suffering from a significant decline of oil prices beginning in the second half of 2014. However, prices began to climb in the first half of 2016. US total crude oil production averaged 8.9 million barrels per day in 2016, down slightly from 2015 levels which were the highest levels of production since 1986. Unlocking reserves found in shale rock is credited with this boom in oil production.

States leading American crude oil production are: Texas; North Dakota; California; Alaska; Oklahoma; New Mexico; and Louisiana. However, only Texas produces more oil than produced in the federal offshore properties.

The country's rising oil production is being met with declining domestic oil consumption due to stricter fuel-efficiency policies, as well as a slow-down in many sectors of the economy. This, together with the rise in natural gas production, has many experts predicting that the US will achieve energy independence within the next 20 years.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

Oil is a critical resource for the US. Oil meets about 37 per cent of US energy demand.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

The share of US consumption met through domestic oil production has been growing since 2005. In 2016, only 25 per cent of the petroleum consumed by the US depended on net petroleum imports.

2.4 To what extent is the your jurisdiction's oil production exported?

Until the end of 2015, US oil exports were made up almost entirely of refined petroleum products, not crude oil. Those exports averaged 5.26 million barrels per day in 2015. The bulk of these petroleum exports went to Mexico and Canada.

In December of 2015, the 40-year general ban on crude oil exports was lifted. By August of 2017, the US was exporting an average of 772,000 barrels per day of crude oil. In light of the shale boom, the light, sweet crude derived from shale formations, which is not well-suited for the US Gulf Coast refineries, represents a particularly attractive commodity to export.

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

The determination of a legal and organisational framework applying to oil and gas activities depends in part on whether the underlying resources are owned by the government or private parties and whether the location is onshore or offshore.

The development of oil and gas reserves on federal lands occurs through leasing programmes managed by the Department of the Interior (DOI). Upstream activities on federal onshore properties are governed by the Mineral Leasing Acts of 1920 and 1947 and are regulated by the Bureau of Land Management (BLM), an agency that is part of the DOI. The BLM reviews and approves permits and licences for companies to explore and develop oil and natural gas on federal lands, and, once projects are approved, it enforces regulatory compliance. Offshore development is governed by the Outer Continental Shelf Lands Act and is regulated by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). BOEMRE, a bureau in the DOI, is the agency that manages the exploration and development of lands lying seaward of state coastal waters that are under US jurisdiction (the outer continental shelf or OCS).

At the state level, public agencies generally regulate oil and natural gas development and production, while the leasing of private land for oil and natural gas development is generally left up to each individual land owner.

The regulation of transportation of oil and natural gas in the United States is divided between the federal government and state authorities. The Federal Energy Regulatory Commission (FERC) is the primary federal regulatory agency governing oil and natural gas transportation. The FERC's regulatory authority extends to the interstate transportation of oil and natural gas, the importing of oil

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and natural gas by pipeline or LNG import terminals, and certain environmental and accounting matters. Actual construction of LNG terminals (import and export) is primarily regulated by the FERC, if the terminals are onshore, and by the Maritime Administration and Coast Guard if they are offshore. State regulatory agencies have jurisdiction over retail pricing, consumer protection, natural gas facility construction, and environmental issues not covered by the federal agencies.

Possible federal regulation from Congress and the Environmental Protection Agency (EPA), relating to an extraction method for natural gas known as hydraulic fracturing (dubbed "fracking"), could be on the horizon. The EPA continues to study the potential environmental risks of fracking. In December of 2016, it released a report which linked fracking to water pollution in some circumstances. However, uncertainties and data gaps remain in the studies. The role of fracking in earthquakes also remains controversial. State and local governments are also involved in these controversies.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

In the US, rights to oil, gas and other minerals are generally held by the owner of the surface until and unless the mineral rights are severed and granted to others. To the extent governmental bodies control those rights, i.e. in state and federal government-owned lands and offshore, those rights are conveyed through leases, as is the case with mineral rights owned by private parties. These leases convey non-vested protectable property rights that may be regulated and their value diminished for a proper government purpose. In general, the mineral estate owner/lessee has the right of reasonable access to and use of the surface estate in order to exploit the minerals.

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

Authorisations for the various stages of development are generally addressed in the oil and gas lease agreement. Typical provisions in natural gas project leasing include: 1) a granting clause, which describes the substances that can be explored and developed; 2) provisions that define the lessee's right to surface operations; 3) delay rental terms, under which a lease automatically terminates if drilling is not started in a specified timeframe unless a payment is made; 4) dry-hole and shut-in provisions that allow for extension of the term of the lease when no hydrocarbons are discovered or production ceases; 5) a royalty clause, which allocates to the lessor a portion of the hydrocarbons produced; and 6) pooling provisions, granting the lessee the right to consolidate the leased land with adjoining leased tracts.

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

Neither the federal government nor individual state governments have an ownership interest or participate directly as a party in the development of oil and natural gas reserves except under lands owned by such governments. The United States does hold an ownership interest in the mineral estate under federal lands, except where otherwise transferred. The situation is similar with respect to lands owned by the individual states. Pursuant to the Mineral Leasing Act and Outer Continental Shelf Lands Act, the federal government leases federal lands for exploration and production of natural gas, and collects royalties on the gas produced.

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Federal and state governments mainly derive value from oil and natural gas development through leasing mineral estates underlying federal and state lands and the collection of royalty payments. Under the Mineral Leasing Act, for example, leases are conditioned upon payment to the government of a royalty of at least 12.5 per cent in amount or value of the gas production that is removed or sold from the leased land. In addition to royalties, leases are conditioned upon payment of annual rental fees. Income taxes as well as oil and gas production or severance taxes and the like are also imposed by various governmental bodies having jurisdiction over applicable reserves.

3.6 Are there any restrictions on the export of production?

Section 3 of the Natural Gas Act of 1938, as amended, requires that anyone who wants to export natural gas to a foreign country must first obtain an authorisation from the DOE. Crude oil exports are regulated by the Energy Policy and Conservation Act, as amended (EPCA). See additional details in the responses set forth in sections 4 and 5 below.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

There are currently no currency exchange restrictions or restrictions on the transfer out of the jurisdiction of funds derived from production.

3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

As a general matter, for privately owned lands, there are no restrictions on the transfer or disposal of oil and natural gas development rights or interests unless specifically provided for in a contract. Leases of privately owned lands may expressly grant or limit the authority of the parties to transfer or assign the lease.

In the case of leases of federal lands, an entity may transfer its interest in the acreage in the lease, with approval of the Secretary of Interior, by assignment of the record title interest or by transfer of operating rights or working interests. At the state level, assignment of a lease, or transfer of rights thereunder, may require approval of state authorities.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

A lessee of federal land must provide the BLM with a bond of at least $10,000 to ensure compliance with all the lease terms, including environmental protection before they begin geophysical exploration

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on leased or public lands. The BLM may require an increase in the bond amount whenever conditions warrant. For multiple leases, a lessee may provide a $25,000 state-wide bond or $150,000 nationwide bond. The BOEMRE also requires bonds in place for federal offshore lease activity. Offshore bonds vary depending on the level of activity on the lease and the number of leases covered by the bond. Offshore bonds may range from $50,000 for a specific lease with no activity, to up to $3,000,000 to cover multiple leases with development operations. Secondary bonds may also be required by the BOEMRE where conditions warrant. States may also require the filing of a bond or alternative security.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

Specific lease terms, or applicable statutes, may restrict granting a security interest in development rights. Otherwise, such rights can normally be pledged for security. Some oil and gas-producing states have special statutory provisions relating to the perfection and priority of security interests in oil and natural gas. Oil and natural gas reserves can be booked for accounting purposes. The basic rules for booking reserves are found in the FASB Financial Accounting Standards, the SEC regulations and the Society of Petroleum Engineers Guidelines for the Evaluation of Petroleum Reserves and Resources.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

A variety of interrelated statutes and agency regulations may apply to the development of oil and natural gas reserves in the United States. One of the more prominent sets of environmental regulations at the federal level is the National Environmental Policy Act (NEPA), which requires a federal agency to prepare an environmental impact statement before any major federal action. As part of the NEPA process, the BLM may require that oil and natural gas developers comply with Best Management Practices to ensure that development on the public lands is conducted in a manner that prevents or lessens its environmental impact on public lands resources. Additionally, the Federal Onshore Oil and Gas Leasing Reform Act prohibits certain types of oil and gas leasing on lands recommended for wilderness allocation. State regulations, such as compulsory pooling and well spacing, may also restrict development of oil and natural gas.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

Section 7(b) of the Natural Gas Act requires a natural gas company to obtain approval from the FERC before abandoning all or any portion of its facilities subject to the jurisdiction of the FERC. The FERC may only permit the abandonment of natural gas facilities upon finding that (1) the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or (2) that the present or future public convenience or necessity permits such abandonment. The plugging and abandonment of oil and natural gas wells are also subject to state regulation and, for federal lands and the Outer Continental Shelf, to regulation by the Department of the Interior.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

A certificate of public convenience and necessity issued by the FERC is required for interstate storage projects under Section 7 of the Natural Gas Act. Generally, absent an exemption, storage facilities must be certificated by the FERC if the natural gas is transported in interstate commerce. Exemptions from FERC jurisdiction over storage projects apply in circumstances where transportation by interstate pipelines has not begun (production, gathering) or has ended, or where the company receives gas from an interstate pipeline within or at the border of its state, if all the natural gas so received is ultimately consumed within that state, and if the rates and service of the company and its facilities are subject to regulation by a state commission (known as a Hinshaw company). Storage projects that are exempt from the Natural Gas Act are regulated at the state level.

Interstate pipelines that already hold blanket, open access certificate authorisations from the FERC may test and develop potential new storage reservoirs over a three-year period without further authorisation. New companies will lack a blanket, open access certificate and thus cannot test and develop potential reservoirs unless the FERC issues temporary certificates and exempts temporary operations from certificate requirements. Under these temporary authorisations, storage developers may conduct activities that are necessary to support the certificate application or to prevent degradation of the field for storage operations.

Prior to certificate approval, tariff and rates for storage services must be developed. Rates can be cost-based or market-based. The EPAct allows the FERC to grant market-based rates for new storage capacity even if a company is unable to demonstrate that it lacks market power as long as the FERC determines (1) that the market-based rates are in the public interest and necessary to encourage the construction of the storage capacity, and (2) that customers are adequately protected.

The FERC requires that storage capacity be allocated to new customers on a non-discriminatory basis. A storage developer can obtain binding commitments for storage services from customers and satisfy the FERC's non-discriminatory access regulatory requirements by holding a so-called "open season".

The certificate process also involves an environmental review, which may require the preparation of an environmental impact statement. The FERC sometimes issues a preliminary determination on non-environmental issues in order to resolve these issues and provide some certainty so that the project may be financed or an open season held. The preliminary determination is subject to the FERC's resolution of environmental issues in a subsequent order.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

Pursuant to Section 3 of the Natural Gas Act, the import and export of natural gas, including LNG, requires authorisation from the Department of Energy's Office of Natural Gas and Petroleum Import and Export Activities. The Department of Energy authorises two types of natural gas imports and exports: blanket authorisations; and long-term authorisations.

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Blanket authorisations allow the authorised party to import or export for up to two years. Blanket authorisations do not obligate the holder of the authorisation to import or export natural gas, and no contracts are required to be filed with the application. Long-term authorisations are used for natural gas imports or exports that will last longer than two years. Typically, holders of long-term authorisations have, or intend to have, a signed gas purchase or sales agreement in place for more than two years.

Although FERC approval is not required for the actual import or export of natural gas, the FERC does oversee the construction and operation of natural gas import and export facilities (with corresponding jurisdiction for offshore terminal approvals resting primarily with the Maritime Administration and the Coast Guard), and has authority to review proposed rates for the interstate transportation and sale of imported natural gas. Formerly, in order to get FERC approval for the construction and operation of an LNG terminal, the FERC required "open access" for all market participants to LNG terminals on a non-discriminatory basis. However, after the Hackberry decision in 2002, which was later codified in the EPAct of 2005, the FERC can no longer deny an application solely on the basis that the applicant proposes to use the LNG terminal exclusively or partially for gas that the applicant or an affiliate of the applicant will supply to the facility; nor can the FERC condition an approval on the requirement that the LNG terminal offers services to customers other than the applicant, or any affiliate of the applicant, in order to secure the order. The FERC also has authority to grant Presidential Permits for natural gas import or export facilities located on the international boundary of Canada or Mexico. The North American Free Trade Agreement (NAFTA) allows for the free trade of natural gas among the US, Mexico, and Canada; exports to member countries are excused from export controls, and imports from member countries will not incur tariffs.

A number of applications have been approved for the export of LNG liquefied from natural gas produced in the United States. Under the Energy Policy Act of 1992, exports to countries with which the US has a free trade agreement are deemed to be consistent with the public interest, and applications for such importation or exportation are to be granted without modification or delay. Applications for export to non-FTA countries are given more scrutiny by the DOE but are being approved.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Exports of oil and oil products are generally prohibited by federal statute. One of the primary statutory controls on exports is The Energy Policy and Conservation Act, as amended (EPCA), originally passed in the wake of the Middle East oil embargos. In December of 2015, the general ban on the export of crude oil was lifted. There is an additional regulation on the export of crude oil transported on pipelines that benefit from federal rights-of-way, are produced on the outer continental shelf, or are produced from the Naval Petroleum Reserve. The Department of Commerce's Bureau of Industry and Security (BIS) regulates crude oil exports under its Short Supply Controls. Export of refined petroleum products are generally permitted and do not require a licence from BIS.

Oil imports may be subject to tariffs ranging from 5.25¢ to 52.5¢ per barrel depending on the type of petroleum. However, oil and petroleum products from certain free trade agreement and preferential trade programme countries receive duty-free treatment.

6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

The FERC regulates interstate pipelines that transport oil and natural gas in interstate commerce, whereas intrastate pipelines that operate wholly within a single state are generally subject to regulation by the state within which they operate. The FERC regulates the rates and services offered by interstate pipeline companies, and, with respect to natural gas pipelines, the FERC regulates the construction and abandonment. A key component of the regulatory framework is that pipelines must offer access to their transportation infrastructure to all market participants on a non-discriminatory basis, referred to as "open access", allowing marketers, producers, LDCs, and end-users access to transportation services, on an equal basis. Interstate pipelines can serve only as transporters of natural gas and are no longer permitted to act as merchants and sell bundled products.

The FERC has defined "transportation" to include "storage", "exchange", and "backhaul" and the rates, terms and conditions for each of these services are set forth in each pipeline company's FERC-approved tariffs.

There is a significant difference between the way the FERC regulates natural gas pipelines pursuant to the Natural Gas Act (NGA) and oil pipelines pursuant to the Interstate Commerce Act of 1887 (ICA). Pursuant to the NGA, a company must obtain FERC authorisation to construct, commence service on, or abandon an interstate natural gas pipeline. The FERC decides whether the proposed natural gas pipeline project is in the public interest and whether the rates and terms of service are in the public interest. In addition, when the FERC certifies a natural gas pipeline, the pipeline developer can rely on the FERC's federal eminent domain authority and federal pre-emption of state and local laws that might otherwise interfere with the FERC-approved project.

In contrast, oil pipelines have a unique regulatory model with a sharing of federal and state jurisdiction. The FERC regulates oil pipelines rates and tariffs, but there is no requirement for FERC to approve an oil pipeline's rates or tariff prior to commencement of service, nor does the FERC have jurisdiction over oil pipeline entry, construction, commencement of new services or abandonment. Oil pipeline developers may not rely on the FERC's federal eminent domain authority. Instead, developers of interstate oil pipelines must navigate each different state's rules and regulations governing the construction of pipelines and permitting processes.

Oil and natural gas pipelines are also subject to various environmental and safety laws during the construction and operation of the transportation facilities. Once pipeline projects become operational, safety is regulated, monitored and enforced by the Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA).

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

For the construction of interstate natural gas transportation pipelines and associated infrastructure, Section 7 of the NGA mandates that developers obtain FERC approval, in the form of a "certificate of public convenience and necessity" authorising the construction,

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operation or expansion of such facilities. Under Section 7(c), the FERC will grant a certificate if it determines that the proposed project is in the public interest. Any abandonment of "certificated transportation facilities" must also be approved by the FERC, as required in the public interest under Section 7(b) of the NGA. Part 157 of the FERC's regulations allow for public participation in the certification process and require applicants to make a good faith effort to provide notice of the proceeding to affected persons, such as land owners, and state and local governments where the project is located.

Project construction for pipelines must also comply with multiple environmental statutes including, but not limited to, the Clean Water Act, the Clean Air Act, the Coastal Zone Management Act of 1972, and the Endangered Species Act of 1973. In October of 2006, the FERC finalised rules for the co-ordination of all federal environmental reviews and authorisations for natural gas infrastructure projects to ensure that the required authorisations are processed expeditiously. Under those rules, the FERC acts as the lead agency for federal environmental reviews, establishes a schedule for the completion of reviews of requests for authorisations necessary for a proposed project and maintains a consolidated record of those decisions to expedite potential judicial review.

In contrast to natural gas pipelines, no similar certifications are required from the FERC or any other federal agency for the siting and construction of domestic oil pipelines. Oil pipeline developers must work under each state's regulatory and permitting regime and are subject to various state and federal environmental and safety laws. However, before a company may construct and operate a pipeline to transport natural gas or crude oil between the United States and a foreign country, it must obtain a presidential permit.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Developers may acquire land rights through purchases from individual land owners or through negotiation of rights-of-way, or easements.

With respect to natural gas pipelines, Section 7(h) of the NGA also allows a natural gas pipeline certificate holder to obtain such rights through federal eminent domain, i.e., the inherent power of the government to compel a land owner to surrender certain rights to land in exchange for just compensation.

Unlike natural gas pipelines, oil pipelines lack the federal eminent domain authority and federal pre-emptive rights that accompany the FERC natural gas certificate process. Oil pipelines must rely on differing state laws of eminent domain.

Eminent domain procedures are also generally available under state law for common carrier pipelines located within the state.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

The NGA established a regulated system of private contract carriage for natural gas pipelines. Pursuant to the FERC's rules and regulations, access to natural gas transportation pipelines and associated infrastructure is available to market participants on a non-discriminatory basis. FERC Orders Nos. 436 and 636 require that interstate pipelines offer open access to all qualified shippers on a non-discriminatory basis. While an interstate natural gas pipeline is not required to provide requested transportation services for which capacity is not available or that would require the construction or acquisition of new facilities, it must provide available capacity without preference in the quality of service provided, the duration of service, the categories, prices, or volumes of natural gas to be transported.

The ICA established a system of oil pipelines as common carriers instead of contract carriers. This means that oil pipelines must provide a transportation service to any party that reasonably requests service, even where capacity is constrained. Where a new customer requests service on a capacity-constrained oil pipeline, the existing customers may all lose some of the capacity they would otherwise have had.

Pipelines are required to have on file with FERC tariffs of general applicability that provide for the rates, terms and conditions applicable to the various services offered on the pipeline. The FERC's open access regulations govern the various services offered by the pipeline, including firm and interruptible service, temporary or permanent release of capacity that shippers previously subscribed to on the pipeline, and business practices for pipeline operations and communications.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

The US natural gas pipeline network is a highly integrated transportation and distribution grid that can transport natural gas to and from nearly any location in the lower 48 states. Shippers can choose from a number of alternate routes to move gas from production areas to market areas and to access storage facilities. In 2000, the FERC created the framework for market participants to obtain interconnection, provided the following five conditions are satisfied: (i) the party seeking the interconnection must agree to bear the costs of constructing the interconnection; (ii) the proposed interconnection must not adversely affect the pipeline's operations; (iii) the proposed interconnection and resulting transportation must not result in diminished service to the pipeline's existing customers; (iv) the proposed interconnection must not cause the pipeline to be in violation of any applicable environmental or safety laws or regulations with respect to the facilities required to establish the interconnection; and (v) the proposed interconnection must not cause the pipeline to be in violation of its right-of-way agreements or any contractual obligations with respect to the interconnection facilities. The FERC's policy objective is to ensure that competitive markets operate fairly with open access to the pipeline systems.

However, the FERC has held that the ICA does not grant the FERC the authority to order an interconnection between oil pipeline carriers (Enbridge Energy, L.P., 139 FERC 61,134 (2012)). The plain language of the ICA requires carriers to provide facilities to allow for the interchange of traffic between existing lines and existing connecting lines and requires carriers to refrain from discriminating among connecting lines. Many view this discrepancy of FERC authority over natural gas pipelines and oil pipelines as a growing industry issue that needs to be addressed.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

As noted in question 6.4, while interstate pipelines are required to provide open access transportation service, an interstate natural

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gas pipeline is not required to provide requested transportation service for which capacity is not available or that would require the construction or acquisition of any new facilities; however, an interstate oil pipeline is required to provide capacity to all customers, and capacity for each customer may be reduced to accommodate a new customer. Within the natural gas transportation infrastructure, a notable exception to the open access requirement, as mentioned in question 4.1, applies to LNG terminals.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

The FERC has authority over the rates, terms and conditions for service over interstate natural gas transportation facilities, and, pursuant to its authority under Sections 4 and 5 of the NGA, the FERC ensures that rates, terms and conditions are "just and reasonable". Traditionally, rates that are costs-based are deemed "just and reasonable", i.e., the rates allow the pipeline operator an opportunity to recover the costs and expenses of operating the pipeline (including taxes and depreciation), as well as a fair return on the capital invested in the pipeline. An interstate pipeline's cost-based rates are established by the FERC in a Section 4 rate proceeding, which is frequently lengthy and complex. Essentially, the FERC examines the pipeline's books and records to ensure that the proposed rates properly reflect the pipeline's prudently-incurred cost of providing transportation services. The approved rates are incorporated in the pipeline's tariff on file with the FERC and represent the maximum rate the pipeline can charge for transportation services. Pipelines and shippers, however, are free to negotiate a discount to that maximum rate, provided it is offered on a non-discriminatory and non-preferential basis.

The FERC also permits pipelines that lack market power to request negotiated rates for shippers, provided the customers have access to recourse rates under an approved tariff. In order to implement a negotiated rate transaction, a pipeline must file either the negotiated rate agreement itself or a tariff sheet describing the agreement.

Continuing its efforts to "carry out Congress' mandate to protect consumers by protecting the integrity of the markets for physical gas", the FERC issued two orders intended to increase transparency of price and availability of supply in natural gas markets. See Pipeline Posting Requirements under Section 23 of the Natural Gas Act, 125 FERC 61,211 (2008) and Transparency Provisions of Section 23 of the Natural Gas Act, Order No. 704, 121 FERC 61,295 (2007). In both cases, the FERC exercised its expanded market transparency authority under Section 23 of the NGA, a section added to the NGA by the EPAct. The first order requires both interstate and certain major non-interstate pipelines to post on a daily basis capacity, scheduled flow information and actual flow information. According to the FERC, the requirement would provide a complete picture of daily supply and demand information across the United States. The FERC believes that the additional information required of pipelines will improve the efficiency of physical flows of natural gas across the United States' pipeline system and facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce to implement Section 23 of the NGA.

The second order, among other things, introduces a new annual reporting requirement for any buyer or seller of more than 2.2 million mmBtus of physical natural gas each year. Such entities must report aggregate volumes of relevant transactions, including total volume of sales and purchases, volume of transactions at fixed prices and volume of transactions reportable to price index publishers. Buyers or sellers operating under a blanket sales certificate authority that buy or sell less than that amount of gas must also submit an annual report for identification and certain reporting purposes, but need not report aggregate volumes of relevant transactions. A market participant that buys or sells less than that amount of gas and does not operate under a blanket sales certificate authority is not required to submit the annual report. The annual report is due on 1 May of each year.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Although some large end-use customers (e.g., industrial, commercial, and electric generation customers) receive natural gas directly from high-capacity interstate and intrastate pipelines (addressed in question 4.1), state-regulated LDCs distribute the majority of natural gas to end-users through thousands of miles of small-diameter distribution pipe. There are two basic types of local distribution companies: (1) investor-owned utilities; and (2) public gas systems owned by local municipals, co-operatives or other governmental bodies.

The retail sale and distribution of natural gas in the United States is regulated by the individual states and localities in which the LDCs operate, and extends to the rates charged to various classes of customers (e.g., residential, small commercial, commercial and large industrial customers), as well as a range of operational issues such as curtailment, balancing and other general terms and conditions of service. There are regulatory commissions in all 50 states which supervise the rates, services and operations of LDCs. Traditionally, LDCs have been awarded exclusive franchise rights to distribute and sell natural gas in a specified geographic area. However, some states have created retail choice programmes in which customers have the option to choose from whom they purchase their gas and require the LDCs to provide distribution services.

Certain aspects of the operation of natural gas distribution lines are also subject to the safety and security regulations of PHMSA, as noted in question 6.1. Compliance with certain PHMSA rules has been delegated to state authorities.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

LDCs are typically granted franchises or charters by state or local governments to provide gas distribution services in an exclusive service territory. The procedures under which an LDC may expand or transfer its franchise rights vary under state law.

7.3 How is access to the natural gas distribution network organised?

Access to the various distribution systems across the United States is a matter of state law and policy generally administered by state public utility commissions and varies by state. Generally, LDCs must provide distribution services to all customers located on their distribution system on a non-discriminatory basis.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

The standards under which LDCs may be compelled to grant

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capacity or expand their systems for new or existing customers are established on a state-by-state basis.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

The rates and terms under which LDCs must offer services over their systems are established on a state-by-state basis and vary among the states. Generally, the rates and services of an LDC are subject to regulation by a state commission.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

In general, the acquisition or transfer of distribution network assets that are necessary in the provision of service to the public may require the prior approval of a state commission in which the assets are located, but the specific restrictions and limitations vary from state to state. Frequently, state law requires a demonstration that the acquisition of a gas utility or transfer of utility assets is in the public interest, either by showing no net harm to, or net benefits for, customers resulting from the transaction. The Federal Trade Commission (FTC) and the Department of Justice (DOJ) also have authority under the Hart Scott Rodino Antitrust Improvements Act of 1976 (HSR) over mergers and significant acquisitions of – and by – natural gas distribution companies, as discussed in section 10 below.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Until 1985, when the FERC issued Order No. 436 authorising third-party transportation on interstate gas pipelines, there was no natural gas trading to speak of. Gas producers sold their production to the pipeline owners who, in turn, sold to LDCs and large industrial users. This dramatic change in the regulatory environment opened the way for the dramatic increase in natural gas trading over the past 25 years. The market situation was further enhanced with the issue of Order No. 636 in 1992, which completed the unbundling of gas sales and transportation services on interstate pipeline systems.

Natural gas traders can be affiliated with producers, with interstate pipelines or with LDCs or they can be completely independent. A trader who is affiliated with a pipeline or an LDC must conduct itself in an arms-length, independent manner in dealings with its affiliate. While pipelines and LDCs remain closely regulated, natural gas traders are not heavily regulated. FERC Order No. 547 grants any person who is not an interstate pipeline the blanket authority to purchase and resell natural gas. Those purchases and sales are made at negotiated, free market prices. This blanket authority does not subject the certificate holder to any other regulation by the FERC under the NGA, and there is no requirement to file rates or contracts with the FERC.

A major pricing point for natural gas futures contracts and spot sales in the United States is the Henry Hub, a junction of nine interstate and four intrastate pipelines. Henry Hub is located in Erath, Louisiana and is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).

Growing out of several high-profile market manipulation cases in the early 2000s, the FERC promulgated a "code of conduct" for persons holding blanket marketing certificates to protect against market manipulation. FERC Order No. 673 requires sellers, to the extent they report transactions to publishers of natural gas indices, to notify the FERC of the details of their arrangement, report the information accurately, update the FERC on any change in their reporting practice, and "adhere to any other standards and requirements for price reporting as the Commission may order" (18 C.F.R. § 284.403(a)). The code of conduct also directs blanket certificate holders to retain, for a period of five years, "all data and information upon which it billed the prices it charged for the natural gas sold pursuant to its market-based sales certificate or the prices it reported for use in price indices" (18 C.F.R. § 284.403(b)). In addition, EPAct amendments to the NGA in 2005 significantly increased the FERC's authority to impose penalties and fines for market manipulation and cover-ups. This trend has continued with the issuance of FERC Order No. 704 to improve the transparency of wholesale natural gas prices and supplies, together with significant enforcement activities.

8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

Natural gas is traded in its physical state and in the form of futures contracts, as well as through "hedges" and other derivatives. Under FERC Orders Nos. 436 and 636, the sale and trading of natural gas has been "unbundled" from interstate transportation services. At the state level, the sale and distribution of natural gas was traditionally sold as a bundled service, but in recent years several states have introduced retail choice programmes that allow LDCs' customers to purchase natural gas from third-party suppliers.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

LNG projects are subject to various laws and regulations that are administered by agencies of the federal government, DOE, EPA, FERC, the US Coast Guard/Maritime Administration, and the US Army Corps of Engineers, as well as the individual states.

To construct an LNG facility, import authorisation from the Department of Energy's Assistant Secretary of Fossil Energy must be obtained. The Assistant Secretary must approve the application unless it determines that the import is not consistent with the public interest. After the import authorisation is obtained, the FERC must review the application pursuant to its exclusive jurisdiction under Section 3 of the NGA. Depending on the location of the proposed project (onshore or offshore), the US Coast Guard and Maritime Administration (MARAD) may have jurisdiction. The US Coast Guard and MARAD has jurisdiction for the siting and operation of all LNG import terminals in federal waters, pursuant to the Deepwater Ports Act. The FERC's authority, as amended under the EPAct, is addressed in question 9.2.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

As noted in question 9.1, the first step in obtaining approval for the

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construction and operation of an LNG facility in the United States is to present an application to import gas to the Assistant Secretary of Fossil Energy at the DOE.

Pursuant to Section 3 of the NGA, (as amended by the EPAct), the FERC has exclusive authority to approve or deny an application for the "siting, construction, expansion, or operation" of onshore LNG import terminals, offshore import terminals in state waters, as well as pipelines and other onshore LNG facilities. The FERC must review the environmental impact of the proposed LNG project pursuant to the National Environmental Policy Act (NEPA) and for compliance with other environmental and safety standards. This includes a review of the potential impact to public safety, including thermal and flammable vapour exclusion zone modelling, and marine safety analysis. The FERC also conducts a Cryogenic Design Review to verify the safe design of the facilities and the reliability of the system. As part of the approval process, the company must obtain a water quality certificate, a dredge fill permit and Coastal Zone Management clearance from the state in which construction will occur.

The FERC continues to monitor the design and construction of the project through detailed monthly reports. After construction is complete, prior to commencing operations, the company must receive written approval from the Director of the Office of Energy Projects. Thereafter, the facility will be subject to periodic inspection by the FERC, and the operator is required to file semi-annual reports summarising plant operations, maintenance activity and accounts of any abnormal events. The Department of Transportation has authority under the Pipeline Safety Act to prescribe minimum operation, maintenance and safety standards for the location, design, installation, construction, inspection and testing standards of LNG facilities.

The US Coast Guard and Maritime Administration administer a similar process for the approval of LNG projects in federal waters. Pipelines leading from deepwater LNG terminals come under FERC jurisdiction above the "high water mark" when the pipeline comes onshore.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

The LNG sector is lightly regulated by the FERC. LNG projects are not required to offer open access service or to maintain tariffs or rate schedules. The rates, terms and conditions of LNG terminalling services are mutually agreed to by the parties. The EPAct provides, however, that any order for an LNG terminal that offers open access shall not result in subsidisation of expansion capacity by existing customers or degradation of service to existing customers.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

Unlike interstate pipelines, where open access regimes are required by the FERC, third-party access rights to LNG facilities depend upon the market and contractual circumstances of a particular LNG facility. Currently, after the Hackberry decision in 2002, later codified in the EPAct of 2005, the FERC cannot deny an application solely on the basis that the applicant proposes to use the LNG terminal exclusively or partially for gas that the applicant or an affiliate of the applicant will supply to the facility; nor can the FERC condition an approval on the requirement that the LNG terminal offers service to customers other than the applicant, or any affiliate of the applicant, in order to secure the order.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

Since the 1990s, the US petroleum market has been relatively free from legislation that regulates, subsidises or taxes oil. However, the Petroleum Marketing Practices Act (PMPA) (15 U.S.C. §2801–2806) sets certain requirements for contracts between gasoline refiners or distributors and their retailers.

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Physical trading of oil is carried out by oil producers and oil trading merchants who buy, store, transport and sell oil. Crude oil futures and options are traded through standardised contracts on commodities exchanges, primarily the New York Mercantile Exchange (NYMEX). The main contract for trading futures and options is the NYMEX contract for West Texas Intermediate crude, priced for delivery at Cushing, Oklahoma, the country's largest point for storage and delivery of crude oil. Oil trading is regulated primarily by the US Commodity Futures Trading Commission (CFTC).

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

Competitive and anti-competitive practices in the industry are monitored mainly by the Department of Justice (DOJ), Federal Trade Commission (FTC) and Federal Energy Regulatory Commission (FERC). The DOJ and FTC enforce the anti-competition laws of general application (called "antitrust laws" in the US) established under the Hart Scott Rodino Antitrust Improvements Act of 1976 (HSR), the Clayton Antitrust Act (1914), the Federal Trade Commission Act (1914) and the Sherman Antitrust Act (1890). In addition, certain FERC orders are designed to prevent anti-competitive behaviour in the natural gas markets. Competition principles also inform the review and approval by the FERC of the rates and of tariffs for transportation and storage service. The FERC created its own Office of Enforcement with responsibility for identifying and taking action against fraud and anti-competitive practices in the electricity and gas sectors. The FERC and Commodities Futures Trading Commission monitor oil and natural gas trading practices. In addition to the federal agencies, most states have antitrust laws generally based on the federal antitrust statutes that are enforced by the state attorney general or private plaintiffs.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

In reviewing mergers or acquisitions in the gas market, the FTC and DOJ examine whether the effect "may be substantially to lessen competition, or to tend to create a monopoly". The EPAct provides that it is unlawful for an entity to use a "manipulative or deceptive device or contrivance" in connection with any purchase or sale of natural gas or purchase or sale of any transportation services. The individual states also have antitrust laws that may be used to challenge anti-competitive conduct.

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11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

Generally, the regulators have the broad authority to investigate, prevent and penalise unfair methods of competition. All of the federal and state antitrust enforcement agencies have power to seek monetary damages and a variety of equitable remedies for violation of the anti-competition laws they are authorised to enforce. Many of these laws carry criminal penalties, and damages are subject to increase for punitive or exemplary purposes. The EPAct grants the FERC authority to impose fines or penalties of up to $1 million per day for violations of the NGA, any rule, regulation or order issued by the FERC. In addition, the Clayton Act authorises private parties to sue for triple damages when they have been harmed by conduct that violates either the Sherman or Clayton Act and to obtain a court order prohibiting the anti-competitive practice in the future.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

HSR requires companies planning large mergers and acquisitions to notify the government of their plans in advance. Approval can be obtained within 30 days following submission of all required information, although the approval process may take much longer if a potentially material effect on competition is suspected. As discussed in question 11.2, the FTC will examine whether the proposed transaction significantly lessens competition in the relevant market. The FERC has jurisdiction under Section 7 of the NGA to approve the acquisition or abandonment of jurisdictional facilities, but its authority does not generally extend to merger or other changes in control in the business sector.

Many state laws require their public utility commissions to review and approve the change of control of a state jurisdictional gas utility. Generally, state laws require a demonstration that a proposed change of control is in the public interest by showing net benefits for, or no net harm to, customers of the regulated utility. State laws may also require a demonstration that the acquiring entity has the financial, managerial and technical expertise or capability to own and operate the gas utility. Reviews of the change of control of a gas utility by a state public utility commissions normally take three to 12 months for completion.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

Any transaction by or with any foreign person which could result in control of a US business by a foreign person is subject to review by the Committee on Foreign Investment in the United States (CFIUS). CFIUS is an inter-agency committee chaired by the US Secretary of Treasury which conducts reviews of foreign investments pursuant to the Foreign Investment and National Security Act of 2007 (FINSA), which amended Section 721 of the Defense Production Act of 1950. Under FINSA, the US President, acting through CFIUS, is authorised to review foreign acquisitions of controlling interest in US businesses if national security is implicated. The President may prohibit a transaction (or force divestiture of a completed transaction if the transaction has not previously passed muster with CFIUS) that threatens to impair the national security of the United States.

A CFIUS review focuses on a foreign person's power to control a US business, not on the form of the transaction. Thus, a covered transaction may include asset acquisitions, equity investments, joint ventures and long-term leases. Providing notice of a transaction to CFIUS is voluntary, but CFIUS may initiate a review even after the closing of a transaction if approval has not been sought and granted before closing. CFIUS reviews are subject to statutory timeframes that require a CFIUS review of a completed notification within 30 days and completion of an investigation, if deemed necessary, within 45 days, with additional time authorised under certain conditions. FINSA expanded the mandate of CFIUS to review foreign investments, including consideration of the potential effect on critical infrastructure and critical technologies.

Lastly, the Mineral Leasing Act prohibits foreign ownership of leases except through stock ownership in a domestic corporation. The foreign stockholders cannot come from countries that deny similar privileges to citizens of the United States.

12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

The importation or exportation of natural gas to a country with which the United States has an effective free trade agreement is deemed to be in the public interest, and is usually not controversial. For example, applications for export of LNG to free trade agreement countries are generally required to receive automatic approval by the DOE, while applications for export to non-FTA countries are reviewed on a case-by-case basis.

Oil and petroleum imports are often entitled to duty free treatment under several trade agreements and preferential trade programmes.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

There are no provisions mandating compulsory dispute resolution procedures in suits with the government. For private parties, the FERC adopted Order No. 578, which allows parties to voluntarily submit disputes to alternative dispute resolution procedures, such as settlement negotiations, conciliation, facilitation, mediation, fact-finding, mini-trials and arbitration.

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13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Although the United States is a signatory of the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, it applies the Convention "only to recognition and enforcement of awards made in the territory of another Contracting State", and only to "differences arising out of legal relationships whether contractual or not which are considered as commercial under the national law". The United States is also a signatory to the Convention on the Settlement of Investment Disputes between States and Nationals of Other States.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

As natural gas production, transmission and local distribution facilities in the United States are not typically owned by the federal government or by the individual states, this question has limited application in the United States. Moreover, such suits would be subject to the restrictions of the Eleventh Amendment to the United States Constitution and the doctrine of sovereign immunity.

Certain distribution systems may be owned and operated by municipalities or other governmental entities, and the extent to which judgments may be enforced against such entities is a matter of state law and, therefore, varies among the states.

13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

Yes. An example of such litigation is the case of *TransCanada PipeLines Ltd. v F.E.R.C.*, 24 F.3d 305 (D.C. Cir. 1994). In that case, the District of Columbia Circuit ruled in favour of Canada-based TransCanada. The D.C. Circuit found that the FERC arbitrarily departed from its own precedent by directing the pipeline company to recover costs of expansion incrementally, thus violating the non-discriminatory provisions of the Natural Gas Act and imposing unfair retroactive remedies.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

Crude Oil Exports

In December of 2015, the 40-year general ban on crude oil exports was lifted. By August of 2017, the US was exporting an average of 772,000 barrels per day of crude oil. In light of the shale boom, the light, sweet crude derived from shale formations, which is not well-suited for the US Gulf Coast refineries, represents a particularly attractive commodity to export.

Energy Policy Modernization Act

In the summer of 2016, the United States Senate passed an almost 800-page bill dealing with many aspects of energy, called the Energy Policy Modernization Act. One of the more significant provisions of the bill dealt with improving the procedures for the export of domestically produced natural gas by way of LNG. The bill fell just short of passage in a bicameral Congressional conference at the end of 2016. A new bill, the Energy and Natural Resources Act, was introduced in 2017. It builds on the Energy Policy Modernization Act, addressing a wide range of issues. It features 11 titles on the following topics: efficiency; infrastructure; supply; accountability; conservation; federal land management; National Park System management; sportsmen's issues; water infrastructure; natural hazards; and Indian energy.

Election of Donald Trump as President

In view of the election of Donald Trump as President in November of 2016, a regulatory environment that is more friendly to the energy industry is evolving, but vocal opposition to many initiatives of the new administration are surfacing. The current White House administration, with its "America First Energy Plan", has created an environment that many consider very friendly to the oil and gas industry. Regulations have been aggressively rolled back and goals of "energy independence" and "energy dominance" set. Changes were implemented very quickly, causing some in the industry to become concerned about uncertainty and the impact on oil prices. As changes continue to be made, it remains to be seen how they will impact the industry over time. What is certain is that all of this change will come with unique challenges.

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Stone Pigman Walther Wittmann

Stone Pigman Walther Wittmann PLLC has extensive experience assisting clients in all aspects of energy-related transactions, business formations, project financings, M&A, strategic alliances and the purchase and sale of major energy assets. In addition to developing project structures, we often serve as lead counsel on contracts for joint ventures, joint operations, sales and purchases, processing, services, transportation, development, investment, production sharing, farm-out agreements, drilling, storage, construction, operation and management and technology licensing.

We have handled hundreds of domestic and international energy deals that involve the exploration, extraction, processing, transportation and sale of hydrocarbons, renewables and other natural resources. Our clients include small and large entities, major and independent oil companies, drilling companies, oil field service providers, lenders, developers, government agencies and foreign investors.

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Chapter 29

Venezuela

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1 Overview of Natural Gas Sector

1.1 A brief outline of your jurisdiction's natural gas sector, including a general description of: natural gas reserves; natural gas production including the extent to which production is associated or non-associated natural gas; import and export of natural gas, including liquefied natural gas (LNG) liquefaction and export facilities, and/or receiving and re-gasification facilities ("LNG facilities"); natural gas pipeline transportation and distribution/transmission network; natural gas storage; and commodity sales and trading.

The current data on Venezuelan gas reserves is not uniform and hence there can be interesting differences between what the Venezuelan Government reports and what independent parties report. Under any of the sources, Venezuela maintains the largest reserves of natural gas in the Americas, and some of the largest reserves worldwide.

Data provided by State-holding oil and gas company "*Petróleos de Venezuela, S.A.*" (hereinafter referred to as "PDVSA"), in its financials for financial years 2015/2016, show that at the close of 2016 proven developed reserves totalled 20.27 tcf. Analysts identified that initial commercial gas reserves were at 22.36 tcf and remaining gas reserves stood at 14.88 tcf at the close of 2016. While most of the reserves consisted of associated gas (and hence onshore), most of the non-associated gas reserves corresponded to offshore projects concentrated in two major areas, *Urdaneta* (located on the north-western shores of Venezuela) and *Mariscal Sucre* (located north-east of Venezuela).

Based on PDVSA's financials for 2016, total natural gas production on December 31, 2016 was estimated at 7,926 mmcfd. NGL production was estimated at 131.3 mbpd. According to the same report, of the whole 7,926 mmcfd of natural gas (mostly methane gas) produced in Venezuela during 2016, 2,476 mmcfd were sold in the domestic market, and 2,260 mmcfd were reinjected to oil fields. Also, 3,192 mmcfd were destined for PDVSA's internal use (mainly as fuel in field and refinery operations).

1.2 To what extent are your jurisdiction's energy requirements met using natural gas (including LNG)?

Gas does not play a significant role in Venezuela's current energy mix.

With regards to energy generation, according to Venezuela's State-owned electricity utility parent company, CORPOELEC, most of Venezuela's energy generation is supplied from hydraulic sources which make up 61% of Venezuela's electricity generation needs, while the remainder is generated from fossil fuels, from which diesel makes up a significant amount and gas a limited amount (close to 34%), the remainder is supplied as NGL (mostly in the form of LPG).

Close to 100% of motor vehicles are fuelled with gasoline, even when the Government has put in place programmes to foster the use of natural gas and provided for the mandatory installation of gas systems in most new vehicles; said efforts have fallen short in light of the very limited existence of gas fuelling facilities and the heavily subsidised price of gasoline.

In any case, the importance of gas cannot be downplayed, as it has become a significant alternative for low-income families in urban areas which rely on LPG distribution networks across Venezuela.

1.3 To what extent are your jurisdiction's natural gas requirements met through domestic natural gas production?

Close to all natural gas production is used within Venezuela. Up to 2015, Venezuela imported some 400 mmcfd of gas from Colombia through the Trans Andean *Antonio Ricaurte* pipeline, built jointly between Colombia's Ecopetrol and Venezuela's PDVSA Gas (an affiliate of PDVSA). In its financial reports, PDVSA has not evidenced gas imports for the year 2016 (the same is confirmed in OPEC's yearly report, as well as by some analysts). *Cardon IV* (Perla) production made up for most of the prior shortfall (reserves stand at 6.53 tcf, and production for 2016 stood at 500 mmcfd).

A significant amount of associated gas produced is reinjected into oil field production operations, other amounts are devoted to the petrochemical market (mostly handled by State-owned or -controlled entities), and to energy generation in gas and combined-cycle power plants (handled by PDVSA or CORPOELEC), and some of it is used for domestic gas distribution through gas pipelines or GLP containers consumption.

1.4 To what extent is your jurisdiction's natural gas production exported (pipeline or LNG)?

Gas is produced in Venezuela by PDVSA Gas (a subsidiary of PDVSA) or by private parties (under E&P licences, whether operating on their own or co-ventured with PDVSA), which may be allowed under the law and/or the terms of their licences to market produced gas domestically or overseas (to date, onshore licences allow for exclusive sale in the domestic market, while awarded offshore licences allow for overseas sales or a mixed approach).

No exports of natural gas took place in the year 2016 (or during prior years). The Perla project in the *Dación IV* block is expected to market part of its massive production in international markets on its own, or to sell domestically to PDVSA Gas for the latter to resell both domestically

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and internationally (initially through the use of the *Antonio Ricaurte* pipeline, linking with the Colombian north-eastern market). No other projects (i.e. offshore projects) are expected to advance any export sales any time soon. The parties to the Perla project are still negotiating with PDVSA (which has a buy-in interest in the project) the ratio of export/local sales as well as other significant project issues.

PDVSA Gas is currently responsible for all downstream gas-related operations in Venezuela, including commercialisation. All onshore licensees sell to PDVSA Gas at domestic market rates. It is envisaged that the commercial feasibility for offshore gas projects will rely heavily on the possibility for the licensees to market at least part of the gas produced overseas (which may be needed under current Unitisation Agreements between the Governments of Trinidad & Tobago and Venezuela for certain *Plataforma Deltana* projects).

2 Overview of Oil Sector

2.1 Please provide a brief outline of your jurisdiction's oil sector.

From the second half of 2015 to date, there has been a significant drop in both production and export volumes; this is against a backdrop where the price of oil and oil products in international markets fell sharply and – while increasing somewhat during the first half of 2017 – continues to remain low (in light of the substantial budgetary needs of Venezuela). According to PDVSA's *Financial Statements Management Report* for the financial year 2016, hydrocarbons exports dropped to 2,189 mbd. This represents a reduction compared to the financial year 2015, where Venezuela's exports were close to 2,425 mbd. OPEC puts Venezuela's production during the last quarter of 2016 at 2,021 mbd (according to secondary sources), and during the second quarter of 2017 at 1,955 mbd.

At the end of 2016, proven reserves stood at 302,250 mmb, according to PDVSA's *Financial Statements Management Report* for the financial year 2016. Only 13.56% of the proven reserves (40,995 mmb) correspond to conventional crude oil (condensates, light, medium and heavy oil) and the remaining 86.43% to extra-heavy crude oil reserves (261,253 mmb), most of which is located in the Orinoco Oil Belt ("FPO") area. Significant reserves relate mostly to extra-heavy crude oil, of which the cost of extraction and upgrading tends to be significantly higher. In fact, a closer look reveals that developed reserves stand at 12,944 mmb.

Developing the said reserves requires a significant investment not only in production but also in upgrading the extra-heavy oil ("EHO") to produce synthetic crude oil ("SCO") which may be processed in refineries accepting such a diet, or alternatively, it requires combining the EHO with light oil in order for the same to be marketed as blend (diluted crude oil or "DCO"). Blending avoids the costs and time required for building the facilities needed to upgrade the EHO, but requires buying large amounts of diluent (light crude oil) from overseas in order to blend and sell DCO (at a price lower than the price paid for the diluent).

Under such a scenario, it remains clear that Venezuela's oil and gas future relies on the ability to attract private investors, which may allow for much-needed investment in oil production, and may also allow Venezuela to release financial resources which are gravely needed in dealing with restructuring debt service and supplying basic public goods to the Venezuelan population.

2.2 To what extent are your jurisdiction's energy requirements met using oil?

As referred to above, Venezuela's energy mix is composed mainly by hydro and thermal (fossil fuel) generation.

Based on official data provided by the State-controlled energy company CORPOELEC, 62% of the country's energy is produced in the energy park located in the Guayana Region, which consists of several hydroelectrical generation structures. The other 35% of the energy mix is covered by thermoelectrical generation facilities throughout the rest of the country. Some of these thermoelectric facilities use oil and/or gas in order to generate the necessary heat to initiate their respective process. However, in recent years there have been projects to turn the oil-consuming facilities into only gas-consuming facilities, in order to save oil for trading. This is the case for the *India Urquía*, *Termocarabobo* and *Juan Bautista Arismendi y Luisa Cáceres de Arismendi* generation facilities.

2.3 To what extent are your jurisdiction's oil requirements met through domestic oil production?

In general, all domestic requirements for oil products are met through domestic production. According to the PDVSA's *Financial Statements Management Report* for the financial year 2016, as of December 31, 2016, 510 mbpd was supplied to the domestic market.

2.4 To what extent is your jurisdiction's oil production exported?

Based on the data provided by PDVSA in its financials for 2015/2016, Venezuela exported 1,818 mbpd of crude oil during 2016. The exports were delivered to the following countries:

Country	Volume (mbd)
Aruba	18
Bahamas	13
Belgium	7
China	354
Cuba	45
Curacao	122
France	13
Germany	7
India	429
Jamaica	2
Malaysia	24
Russia	3
Spain	8
Sweden	23
Thailand	5
United Kingdom	4
United States of America	734

3 Development of Oil and Natural Gas

3.1 Outline broadly the legal/statutory and organisational framework for the exploration and production ("development") of oil and natural gas reserves including: principal legislation; in whom the State's mineral rights to oil and natural gas are vested; Government authority or authorities responsible for the regulation of oil and natural gas development; and current major initiatives or policies of the Government (if any) in relation to oil and natural gas development.

Ownership of oil and gas reservoirs located within Venezuela (including its territorial sea, EEZ and continental shelf) is vested on Venezuela as per the Constitution (Article 12), and the same cannot be sold, mortgaged or otherwise encumbered. The ownership and

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management of hydrocarbons reservoirs is vested exclusively at Federal Level (Article 156, cardinal 12 of the Constitution), and hence both ownership (and hence the granting of mineral rights) as well as regulatory powers are vested on the same.

While ownership is vested on the Federal Level of Government ("*Poder Público Nacional*"), under Articles 113 and 302, mineral rights to explore for and extract hydrocarbons can be granted to investors (whether local or foreign), whether acting on their own or co-ventured with the Venezuelan State.

With the passing of the Gas Master Law ("*Ley Orgánica de Hidrocarburos Gaseosos*") in early 1999, the framework has been segregated between gas activities and oil activities. The same was acknowledged in the 1999 Constitution (approved later in the said year), which provides for the reservation of oil activities in its Article 302 (under a reservation, which must be provided for under a Master Law – *Ley Orgánica* – the relevant activity is extracted from the constitutional principle of economic freedom, and hence the activity can only be advanced by private parties if and when approved by the State, and under the conditions provided therefor). The constitutional reservation may expand to other activities if provided by a Master Law, but the current constitutional reservation does not refer to gas activities, nor does it explain whether private parties can engage in oil activities or how, and hence the same is to be supplemented by the law.

An additional provision, Article 303, expresses that the Venezuelan State will own all of the shares of the company created to direct and coordinate the oil activity, i.e. PDVSA. Under the same, PDVSA could not be subject to privatisation by means of sale or disposition of its shares, nor could the same become a publicly traded entity (such as Petrobras or Ecopetrol) as it was envisioned during the second half of the 90s.

The current legal framework for oil is covered under the Hydrocarbons Master Law ("*Ley Orgánica de Hidrocarburos*" or "LOH") issued by means of a Presidential Decree with force of law in 2001, and subject to a single amendment in 2006 (Official Gazette No. 38,493, dated August 4, 2006). The law encompasses oil upstream activities (named primary activities), as well as midstream and downstream activities (excluding gas activities, as referred to below, and petrochemical activities, which are governed by a particular law).

Natural gas activities, which encompass upstream activities on non-associated gas reservoirs as well as midstream and downstream activities on all gas produced (including trading, collecting, processing, industrialising, transporting and distributing, among others) whether from non-associated or associated gas reservoirs, are covered under the Gas Hydrocarbons Master Law ("*Ley Orgánica de Hidrocarburos Gaseosos*" or "LOHG") published in Official Gazette No. 36,793, dated September 23, 1999.

Basic policing and regulatory powers correspond to the Federal Government through the Presidency and the Ministry of Petroleum. In the case of gas activities there is a limited degree of regulatory power vested in the National Gas Agency ("*Ente Nacional de Gas*" or "ENAGAS").

The main legal and regulatory instruments which govern oil activities and which are generally applicable to all participants are: the LOH; General Regulations to the 1943 Hydrocarbons Law (inasmuch as its provisions do not collide with those under the LOH); Decree No. 1,648, dated April 24, 2002, which limits the reservation of oil by-products to the extent they were already traded by PDVSA affiliates; Resolution No. 335, dated December 31, 2004, related to gasoline border trade; Resolution No. 236, dated October 10, 1995, related to the export of fuels; Decree No. 2,335 published in Official Gazette No. 37,734, dated July 17, 2003, the creation of the Commission which sets royalties; Resolution No. 197 published in Official Gazette No. 37,753, dated August 14, 2003, which provides a general consumer tax break for taxpayers dedicated to refining or manufacturing hydrocarbons; and Resolution No. 336 published in Official Gazette No. 37,853, dated December 9, 2004, on fuel retail sales.

The main legal and regulatory instruments governing gas activities are: the LOHG; its General Regulations, as per Decree No. 840 published in Official Gazette No. 5,471, dated May 31, 2002; Resolution No. 194 published in Official Gazette No. 37,505, dated August 14, 2002, which delegates to the ENAGAS certain powers; Resolution No. 216 published in Official Gazette No. 37,645, dated March 7, 2003, which sets the fiscal value of associated natural gas; Resolution for the price setting of methane gas at dispatch centres; Resolution for the setting of distribution charges for methane gas; Resolution No. 165 published in Official Gazette No. 36,227, dated June 13, 1997, for LPG Price Setting; and Resolution No. 197 published in Official Gazette No. 37,982, dated July 19, 2004, regarding natural gas for vehicles.

3.2 How are the State's mineral rights to develop oil and natural gas reserves transferred to investors or companies ("participants") (e.g. licence, concession, service contract, contractual rights under Production Sharing Agreement?) and what is the legal status of those rights or interests under domestic law?

According to the LOHG, E&P activities related to non-associated gas reservoirs can be advanced by State instrumentalities (such as PDVSA Gas) or by private parties. Private parties require a licence issued by the MPPP. Under the LOH, investors may only participate in E&P activities for oil reservoirs by entering into an *Empresa Mixta* joint venture with a PDVSA affiliate.

Licences under the LOHG are granted by the Ministry of Petroleum for the carrying out of exploration and production within the assigned area, at the sole risk of licensee, in exchange for the payment of royalties identified in the law or the licence. The licence affords the licensee a personal right (not a real estate right) which is to be respected while the same remains in force. Such right can be assigned with the prior consent of the Ministry, but cannot be formally pledged, mortgaged or encumbered. The rights include ownership of extracted gas at the wellhead and the ability to freely market the gas (with the limitations provided under the licence). At the end of the term for the licence, the rights and any main assets devoted to the activities revert to Venezuela without any additional compensation and free of charges or burdens. The main terms and conditions are provided in the LOH, its General Regulations and the relevant licence.

Under the LOH a private investor may only participate in E&P activities by co-venturing with a State-owned entity under particular conditions. Said joint venture is called an *Empresa Mixta*, and while under the law there is no particular requirement for a particular legal vehicle or form to be adopted, so far the same has been advanced as a *Compañía Anónima* (a company in shares) where the State instrumentality (a PDVSA affiliate, mostly the "*Corporación Venezolana del Petróleo, S.A.*" or "CVP") owns a majority stake (the law calls for more than a 50% stake, but in practice the State has held a 60% stake), and is vested with positive control of certain managerial decisions and the day-to-day management of the *Empresa Mixta.* The set-up of an *Empresa Mixta* requires Congress' ("*Asamblea Nacional*") approval (which sets a framework of conditions, as well as a Decree granting the relevant hydrocarbons rights, a Resolution from the Ministry of Petroleum determining the relevant area, an *Empresa Mixta* agreement and the company bylaws, among others). One particular feature of the rights afforded is that while said rights encompass ownership of the oil and associated gas extracted at the

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wellhead, there is a reservation on trading and marketing and, as a result, the company can only sell its oil (unless the same is vertically integrated and manufactures products or synthetic crude oil) to a Government instrumentality (commonly "*PDVSA Petróleo, S.A.*" or "PPSA").

3.3 If different authorisations are issued in respect of different stages of development (e.g., exploration appraisal or production arrangements), please specify those authorisations and briefly summarise the most important (standard) terms (such as term/duration, scope of rights, expenditure obligations).

With regards to the LOHG, neither the law nor the Regulations provide for different consents or authorisations by the MPPP at the different stages (e.g. prospection, exploration, appraisal); nonetheless, it is common for the setting of the same in the relevant licence and according to the corresponding tender protocol for the process (if the award is the result of a bidding or auction process). It is also common to set certain minimum exploratory work programmes and a budget, as well as a plan for relinquishment of areas. For pursuing a LOHG E&P licence the conditions are: (i) a description of the project; (ii) the proposed term, which shall not exceed 35 years, renewable for an additional term not exceeding 30 years; (iii) submission of a five-year exploration plan and description of the minimum work programme and budget, which shall be submitted in the same period; and (iv) any special economic consideration offered (i.e. in addition to standard royalties).

3.4 To what extent, if any, does the State have an ownership interest, or seek to participate, in the development of oil and natural gas reserves (whether as a matter of law or policy)?

For oil E&P activities, see the answer to question 3.3 above. In the case of upstream gas activities, some of the licences call for risk exploration and the ability for PDVSA Gas to back in to a limited non-controlling interest (*cf. Cardon IV* project or some of the *Plataforma Deltana* projects).

3.5 How does the State derive value from oil and natural gas development (e.g. royalty, share of production, taxes)?

Regarding the fiscal take, there is a split between upstream oil and upstream gas.

Under the LOH and the relevant award instruments, the *Empresa Mixta* has to pay different royalties, contributions and taxes, which can be considered fairly regressive as most of the same are computed on a gross basis. The standard royalty is 30% of the volume of hydrocarbons extracted, which is topped up with an extraction tax of 3.33%. A reduction to 20% may be afforded under certain conditions in the case of mature or extra-heavy oil fields.

Other royalties and taxes under the LOH include: (i) surface tax; (ii) own consumption tax; and (iii) export registrar tax.

On top of the same, corporate income tax applies, subject to: a particular schedular rate of 50% on the net taxable income of the company (which nowadays is excluded from adjustment per inflation); and a windfall tax, applicable on the *Empresa Mixta* on the local sale of crude oil (and synthetic crude oil) or their exports. It consists of two separate taxes: (a) a tax on extraordinary prices is equal to 20% over any excess of the realisation price for the Venezuelan basket over the price set in Venezuela's annual budget, provided the latter does not exceed USD 80/bbl; and (b) a tax on exorbitant prices, i.e. the realisation price for the Venezuelan basket exceeds USD 80/bbl.

In the case of the latter, the bracket is made up of three different rates as follows: (i) 80% for when the realisation price is in excess of USD 80 but below USD 100; (ii) 90% for when the realisation price is in excess of USD 100 but below USD 110; and (iii) 95% for when the realisation price is in excess of USD 110.

Last but not least, the Congressional approvals to date consistently call for application of a "shadow" royalty, under which the *Empresa Mixta* must ultimately pay an amount if there is an excess of over 50% of the yearly value of crude oil extracted against the sum of all amounts paid during such year, such as income tax, royalty, severance taxes, LOCTI contributions and any other levies, taxes or contributions based on revenues (gross or net).

The regime is far simpler for gas licences, the LOHG sets in favour of the State a royalty of 20%, and certain licences provide for additional royalties commonly ranging between 1% and 7%. Corporate income tax is applied under the general rules, with a top rate of 34%.

3.6 Are there any restrictions on the export of production?

There are no current restrictions for gas, but the LOHG could provide restrictions as the statutes afford priority to the domestic market in a very broad and unspecified manner. The limitations are commonly covered in the relevant licences which refer not only to whether the output will be marketed locally (initial onshore licences, such as those for *YucalPlacer*) or both locally and overseas (*Cardon IV*) but which may encompass the obligation to erect liquefaction facilities and pursue the sale of LNG (such as the licences for *Plataforma Deltana*). It is always advisable to have clear provisions in the relevant licence allowing for the export of produced gas.

As referred to above, in the case of oil production, crude oil may only be sold by the *Empresa Mixta* to a PDVSA affiliate. The LOH and Decree No. 1,648, dated January 15, 2002, have been read as allowing for by-products and synthetic crude oil (SCO) to be exported by the *Empresa Mixta*. It is always advisable to have clear provisions allowing for the export in the approval from *Asamblea Nacional*.

3.7 Are there any currency exchange restrictions, or restrictions on the transfer of funds derived from production out of the jurisdiction?

Oil *Empresas Mixtas* as well as gas licensees are vested with rights (under Exchange Agreements 9 and 37, respectively) to keep the amounts they need in order to comply with their obligations in foreign currency (including payment of dividends to shareholders and payments to creditors).

In the case of foreign investments and financing, under CC35 the bringing of foreign currency into Venezuela by means of international investments (i.e. capital or other forms of equity contributions) and financing in foreign currency may be carried out under DIPRO or DICOM, as identified in the Government programming. This has proven to be a problem, as the programing is fairly opaque.

Under the current F/X Regulations there is no requirement for contributions in foreign currency, or loans granted to companies incorporated in Venezuela, or to branches of foreign companies set up in Venezuela, to be brought into Venezuela or transformed into Bolivars.

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3.8 What restrictions (if any) apply to the transfer or disposal of oil and natural gas development rights or interests?

The transfer of a gas licence requires prior consent from the MPPP, which can withhold the transfer, and approval commonly takes a long time while trying to obtain payment of an "assignment bonus" from the assignee. Further consents may be required from other participants under the respective JOA instruments. In addition, the licences commonly include a limited change in control provision which requires consent from the MPPP.

The transfer of shares in an *Empresa Mixta* also requires consent and possibly right of first refusal of the majority shareholder (CVP) as well as prior consent from the MPPP, and depending on the wording of the *Asamblea Nacional* approval, its approval too. Furthermore, there is a direct and indirect change in control provision which requires the MPPP's consent.

3.9 Are participants obliged to provide any security or guarantees in relation to oil and natural gas development?

Yes, participants are obliged to provide financial securities. Such financial securities extend to: (a) a parent company guarantee to secure performance; (b) the posting of bonds securing completion of exploration commitments and minimum work programmes; and (c) bonds or securities aimed at covering for environmental liabilities and other liabilities associated with the investors' compliance with Venezuelan laws.

3.10 Can rights to develop oil and natural gas reserves granted to a participant be pledged for security, or booked for accounting purposes under domestic law?

No, the rights afforded to develop oil cannot be pledged for security. The same applies with regards to gas licences. There is no local law limitation for private investors in oil or gas E&P activities to book reserves. Generally accepted financial standards (international financial standards as applicable in Venezuela) would apply.

3.11 In addition to those rights/authorisations required to explore for and produce oil and natural gas, what other principal Government authorisations are required to develop oil and natural gas reserves (e.g. environmental, occupational health and safety) and from whom are these authorisations to be obtained?

Some of the key consents and authorisations required are: (i) environmental permits and approvals, to be issued by the Ministry of Environment; (ii) drilling permits from the MPPP; (iii) authorisations for the construction, operation and dismantling of facilities and equipment from the MPPP; (iv) permits for imports, water transport and operations (offshore operations) from the Agency for Waterways (INEA); and (v) permits, consents and supervision from Ministries and agencies in charge of the health and safety of workers such as the INPSASEL, among others.

3.12 Is there any legislation or framework relating to the abandonment or decommissioning of physical structures used in oil and natural gas development? If so, what are the principal features/requirements of the legislation?

There are few rules and regulations regarding abandonment and decommissioning, and the same correspond to arcane provisions under former Hydrocarbons Law Regulations (still in place) and more general rules issued by the Ministry of Environment on the matter. In the case of gas activities, the licence sets the main rules, including the set-up of a trust to fund all relevant costs. In any case, abandonment and remediation must be carried out with the full supervision of the Ministry of Environment. There are also some limited provisions for abandonment in the *Empresa Mixta* agreements.

3.13 Is there any legislation or framework relating to gas storage? If so, what are the principal features/requirements of the legislation?

Gas storage is broadly regulated under the LOHG and its Regulations. No particular technical rules are provided for other than general industry standards as approved and incorporated under the ISO. As storage has been handled exclusively by PDVSA Gas, to date, there seems to be little incentive to set more detailed rules on the matter.

4 Import / Export of Natural Gas (including LNG)

4.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of natural gas (including LNG).

For participants other than those which produce/extract gas (whether from associated or non-associated reservoirs), a prior permit from the MPPP is required for the trading of gas. Gas producers (i.e. those who produce gas within Venezuela under an *Empresa Mixta* or a licence) can market their gas locally or overseas under the terms of the relevant licence.

Where a permit is required, the same applies whether the sale will be an export sale, an import sale or a sale in the domestic market. The permit is akin to a licence and contains most of its terms and conditions. We know of no permit having been issued to date and PDVSA Gas remains as the single marketer in Venezuela.

5 Import / Export of Oil

5.1 Outline any regulatory requirements, or specific terms, limitations or rules applying in respect of cross-border sales or deliveries of oil and oil products.

Crude oil marketing (whether domestic or overseas) is reserved to State-owned instrumentalities. Marketing of synthetic crude oil (i.e. crude resulting from upgrading processes or SCO) and oil products may be carried out under the terms of the *Empresa Mixta* instruments, including cross-border sales. Both PDVSA affiliates may import crude oil and oil products, but in the case of the former, importing light crude oil and oil products remains an important part of the process for upgrading extra-heavy crude oil into SCO or blending the same into DCO.

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6 Transportation

6.1 Outline broadly the ownership, organisational and regulatory framework in relation to transportation pipelines and associated infrastructure (such as natural gas processing and storage facilities).

Since the nationalisation of the oil industry back in 1975, the ownership of transportation facilities and associated infrastructure has remained with State-owned entities (PDVSA affiliates), with the exception of dedicated pipelines for the extra-heavy oil projects (EHOP) of the Orinoco Oil Belt. Here, again, the rules are split for oil transportation (under the LOH) and gas transportation (under the LOHG).

In the case of oil transportation and ownership of the corresponding facilities, the LOH calls for a reservation of activities carried out on pipelines and associated infrastructure which were owned and operated by State-owned entities at the time the LOH entered into force. As such, most of the oil pipeline infrastructure is owned and operated by PPSA, and the same cannot be privatised or sold out for private-party operation. New transportation facilities can be erected and operated, but the LOH is not sufficiently clear as to whether a licence or permit is required.

Under the LOHG, gas transportation is a public service and gas transportation pipelines/systems may be erected and its operation carried out by private parties under permits, which are subject to similar terms and conditions (as applicable, e.g. term, reversion of assets upon termination, etc.) to those of gas E&P licences. Permits allow for exclusive operation for a five-year term and encompass ownership of the system and the ability to collect a tariff. The carrier is liable from entry point to the designated delivery point, and does not hold title to gas being shipped. The LOHG restricts vertical integration, calls for open access, and provides for base tariffs and guidelines to be set by the ENAGAS.

6.2 What governmental authorisations (including any applicable environmental authorisations) are required to construct and operate oil and natural gas transportation pipelines and associated infrastructure?

The MPPP grants a permit for the construction and operation of transportation pipelines and associated infrastructure. Transportation permits identify a relevant area for the purpose of granting a five-year exclusivity right to provide the services for the capacity authorised (expansions and extensions require additional permission). Permission requires a bidding process which may be waived by the MPPP on national interest grounds with prior approval of the National Executive.

Private parties interested in providing transportation services must obtain and keep updated a qualification from the MPPP. The request for a qualification must include any and all documents evidencing technical capability as well as proposals for national participation and content. The same must be updated every three years when no transportation services have been provided during said term.

The environmental and health and security permits required are the same as those indicated in the answer to question 3.11 above.

6.3 In general, how does an entity obtain the necessary land (or other) rights to construct oil and natural gas transportation pipelines or associated infrastructure? Do Government authorities have any powers of compulsory acquisition to facilitate land access?

Needed land (or other) rights to construct and maintain oil and natural gas transportation pipelines and associated infrastructure may be pursued in a negotiated manner by the permit holder; failing negotiation, both the LOH and the LOHG provide for appropriate means for compulsory acquisition or provision of real estate rights (easements and rights or way) or other relevant rights of use or way.

The granting of easements and rights of way under the LOHG and the LOH (the provisions are mostly similar) would require: (a) for privately owned land, if no agreement is met with the owner of the land, court proceedings are to be initiated, under which the court will grant the consent, and experts will determine payable amounts for the rights afforded which is to be deposited; and (b) for Federal Lands ("*Terrenos Baldíos*") the Federal Government and the permit holder shall agree on the amount payable, unless the permit holder is exempted from payment. Expropriation under the LOHG would require a court expropriation proceeding to be carried out as per the general provisions of the Expropriation Law.

6.4 How is access to oil and natural gas transportation pipelines and associated infrastructure organised?

Access to oil transportation pipelines is not covered under the LOH, and the same has not been exercised to date by private parties (i.e. standing alone as carriers) other than by *Empresas Mixtas* or PPSA for the purposes of dedicated projects, such as *Faja Projects*, on the basis of synergy provisions in the relevant *Asamblea Nacional* approvals or the *Asamblea Nacional* agreement. In the said scenarios, the private parties act as carriers, as commonly the owner carries its own oil through the pipeline and only allows use of excess capacity under agreement with third parties. As far as we know, to date, all access has been carried out under agreements between the interested parties.

Under the LOHG and its General Regulations, access is provided for clients under the terms and conditions of the permit (i.e. on the basis of the original proposal which identifies the clients), and the carrier is only obliged to commit to additional services if and when economically viable (to engage in an expansion or extension). The conditions for nominations are to be agreed between the carrier and the shipper, and the risks are borne by the carrier from the entry point through to the delivery point, as identified in the relevant agreement. Other conditions are to be set in supplementary regulations not issued to date. Tariffs are set (as a cap) on a five-year basis by the MPPP and the Ministry of Commerce (acting jointly), but the relevant tariff may be adjusted annually (as per the discretion of the Ministries) as per an efficiency factor (not set to date) and inflation.

6.5 To what degree are oil and natural gas transportation pipelines integrated or interconnected, and how is co-operation between different transportation systems established and regulated?

To date, all gas systems are owned and operated by PDVSA Gas; hence, there are no regulations or agreements regarding integration, interconnection or co-operation in place.

6.6 Outline any third-party access regime/rights in respect of oil and natural gas transportation and associated infrastructure. For example, can the regulator or a new customer wishing to transport oil or natural gas compel or require the operator/owner of an oil or natural gas transportation pipeline or associated infrastructure to grant capacity or expand its facilities in order to accommodate the new customer? If so, how are the costs (including costs of interconnection, capacity reservation or facility expansions) allocated?

Third-party access to oil transportation facilities and associated

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infrastructure is broadly provided for in the LOH (Article 21). The provisions in the old Hydrocarbons Law Regulations (1943) and other arcane regulatory provisions related to open access are to be applied to supplement the LOH provision. Under the same, the carrier must come to an agreement with the shipper(s) if there is spare capacity, and if there is more than one third-party shipper and no agreement is reached the regulations usually call for apportioning the spare capacity on a *pro rata* basis. If no agreement is reached, the MPPP may force access and provide the conditions for the same.

Third-party access under the LOHG and its Regulations calls for the carrier and third-party shipper(s) to agree on conditions and tariffs, and access is compulsory provided there is spare capacity and no clients are adversely affected. If the parties cannot agree on terms and conditions, the MPPP has broad authority to set the same.

6.7 Are parties free to agree the terms upon which oil or natural gas is to be transported or are the terms (including costs/tariffs which may be charged) regulated?

There are no oil tariffs set by the MPPP for oil transportation activities. In any case, to the extent applicable, if there is no agreement between the parties, the MPPP may apply the basic conditions identified in the old Hydrocarbons Law Regulations related to oil transportation concessions. To date, we do not know of a single case where the same has been applied by the MPPP.

Under the LOHG and its Regulations, parties are free to agree on the terms and conditions under which gas will be transported, although there are limitations imposed by the tariffs (caps) identified by the MPPP and the Ministry of Commerce by joint ruling. Joint Resolution No. DM/139 and DM/019 of 2006, which set the distribution charges and methodology, remain in place.

7 Gas Transmission / Distribution

7.1 Outline broadly the ownership, organisational and regulatory framework in relation to the natural gas transmission/distribution network.

Under the LOHG, gas distribution is a public service and distribution systems may be erected and their operation carried out by private parties under permits, which are subject to similar terms and conditions (as applicable, e.g. term, reversion of assets upon termination, etc.) to gas transportation permits. Permits encompass ownership of the system and the ability to collect the charges. The carrier acquires title to the gas at the entry point.

At present, no distribution permits have been issued and most distribution systems are owned and operated by PDVSA Gas, the remainder were privately owned prior to the entering into force of the LOHG.

7.2 What governmental authorisations (including any applicable environmental authorisations) are required to operate a distribution network?

The MPPP grants a permit for the construction and operation of distribution systems and associated infrastructure. Distribution permits identify a relevant area for the purpose of granting a five-year exclusivity right to provide the services. Permission requires a bidding process which may be waived by the MPPP on national interest grounds with prior approval of the National Executive. Periodical qualification similar to the one applicable to transportation permits is required.

The environmental and health and security permits required are the same as those indicated in the answer to question 3.11 above.

7.3 How is access to the natural gas distribution network organised?

Under the LOHG and its General Regulations, access is to be provided for clients as agreed with the distributor, but the MPPP may intervene when the carrier does not provide continuous service or discriminate among clients. The MPPP may determine rules for certain volumes to be allocated to domestic consumption or industrial consumption. Tariffs are set (as a cap) on a five-year basis by the MPPP and the Ministry of Commerce (acting jointly), but the relevant tariff may be adjusted annually (as per the discretion of the Ministries) as per an efficiency factor (not set to date) and inflation.

7.4 Can the regulator require a distributor to grant capacity or expand its system in order to accommodate new customers?

The regulator can require a distributor to dedicate volumes to certain client bases. The regulator cannot require distributors to expand their systems in order to accommodate new customers.

7.5 What fees are charged for accessing the distribution network, and are these fees regulated?

Under the LOHG and its Regulations, parties are free to agree on the terms and conditions under which gas will be transported, although there are limitations imposed by the tariffs (caps) identified by the MPPP and the Ministry of Commerce by joint ruling. Joint Resolution No. DM/139 and DM/019 of 2006, which set the distribution charges and methodology, remain in place.

7.6 Are there any restrictions or limitations in relation to acquiring an interest in a gas utility, or the transfer of assets forming part of the distribution network (whether directly or indirectly)?

The transfer of interest in a gas utility requires prior consent from the Ministry (and the successor-in-interest meeting the required technical qualifications). Pursuant to Article 60 of the Regulations, disposing or retiring essential assets of a distribution network requires the prior consent of the MPPP, and the request is to be submitted at least six months prior to the scheduled date for the retirement or disposition.

8 Natural Gas Trading

8.1 Outline broadly the ownership, organisational and regulatory framework in relation to natural gas trading. Please include details of current major initiatives or policies of the Government or regulator (if any) relating to natural gas trading.

Similar to transportation and distribution, under the LOHG, gas trading can be carried out by private parties under permits. Producers are allowed to market the gas they produce to traders, major consumers or other final consumers. At present, no distribution permits have been issued and PDVSA Gas does all of the trading as an intermediary.

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8.2 What range of natural gas commodities can be traded? For example, can only "bundled" products (i.e., the natural gas commodity and the distribution thereof) be traded?

All natural gas commodities can be traded, i.e. natural gas, methane, natural gas liquids, and other commodities resulting from processing.

9 Liquefied Natural Gas

9.1 Outline broadly the ownership, organisational and regulatory framework in relation to LNG facilities.

There are no particular provisions in the LOHG or its Regulations related to the erection, ownership or operation of LNG facilities, whether in relation to liquefaction facilities, regasification ones, or export/import facilities. Certain gas E&P licences include commitments for the erection, operation, and or supply of gas to LNG facilities in Venezuela (e.g. licences awarded for *Plataforma Deltana*).

There are no LNG facilities in place in Venezuela even though different projects have been advanced and projects for developing and operating liquefaction facilities as part of the *Mariscal Sucre* project.

9.2 What governmental authorisations are required to construct and operate LNG facilities?

No particular provisions are covered in the LOHG.

9.3 Is there any regulation of the price or terms of service in the LNG sector?

There are no regulations in place.

9.4 Outline any third-party access regime/rights in respect of LNG facilities.

There are no particular provisions regarding third-party access to LNG facilities.

10 Downstream Oil

10.1 Outline broadly the regulatory framework in relation to the downstream oil sector.

The downstream oil sector is regulated by the Hydrocarbons Master Law (LOH).

10.2 Outline broadly the ownership, organisation and regulatory framework in relation to oil trading.

Article 57 of the LOH establishes that crude oil trading activities may only be exercised by companies created by the State, while the trading of oil products may be exercised by both private parties and State-owned entities, unless the same is further reserved by the State. No broad reservation regulations have been issued and Decree No. 1,648, dated April 2002, provides for a reservation on trading carried out at said time by PDVSA affiliates; under the rules, *Empresas Mixtas* would be entitled to trade oil products they manufacture (but not crude oil). As such, certain Oil Belt *Empresas Mixtas* are allowed to trade Upgraded Crude Oil (UCO), which is treated not as crude oil but as an oil product.

11 Competition

11.1 Which governmental authority or authorities are responsible for the regulation of competition aspects, or anti-competitive practices, in the oil and natural gas sector?

The MPPP is the governmental authority responsible for the regulation of competition features and anti-competitive practices in the oil and natural gas sectors; with regards to the gas sector, the ENAGAS is vested with powers to oversee and supervise competition in gas pricing, transportation and distribution.

11.2 To what criteria does the regulator have regard in determining whether conduct is anti-competitive?

Since, to date, most of the systems are operated by PDVSA Gas, the regulator has not set any criteria which could be relevant in determining whether conduct is anti-competitive.

11.3 What power or authority does the regulator have to preclude or take action in relation to anti-competitive practices?

The MPPP has broad powers under the LOH and the LOHG to apply penalties, limit anti-competitive practices and, in the case practices breach a legal or regulatory provision or the terms of a permit, to terminate the relevant permit.

11.4 Does the regulator (or any other Government authority) have the power to approve/disapprove mergers or other changes in control over businesses in the oil and natural gas sector, or proposed acquisitions of development assets, transportation or associated infrastructure or distribution assets? If so, what criteria and procedures are applied? How long does it typically take to obtain a decision approving or disapproving the transaction?

Yes, the regulator has the power to approve/disapprove mergers or certain changes in control over businesses in the oil and natural gas sectors. There is no established criteria and the MPPP has acted mostly on a case-by-case basis. When lacking particular provisions, the proceedings for approval would need to be carried out under the terms of general administrative law. Practice shows the MPPP commonly takes a very long time to issue a decision.

12 Foreign Investment and International Obligations

12.1 Are there any special requirements or limitations on acquisitions of interests in the natural gas sector (whether development, transportation or associated infrastructure, distribution or other) by foreign companies?

There are no special requirements or limitations. While the LOHG does not require for the foreign entity to incorporate a special purpose affiliate or domicile a branch in Venezuela to carry out operations, in practice, gas E&P licences have required domiciliation of a branch. It is foreseeable that upstream licences and downstream permits will require a branch domiciliation, at least in the case of the operator (when rights are awarded to several companies under a joint operating agreement or unincorporated joint venture).

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12.2 To what extent is regulatory policy in respect of the oil and natural gas sector influenced or affected by international treaties or other multinational arrangements?

International treaties and multinational arrangements influence Venezuela's regulatory policies on many levels.

With regards to multilateral commitments on oil, OPEC quota system obligations play a significant role and may result in curtailment obligations extending to *Empresas Mixtas*. Other oil multilateral commitments, such as the PetroCaribe energy supply agreement (18 countries are currently participants, Venezuela being the sole supplier), may also affect oil marketing.

Border Delimitation Treaties and subsequent Unitisation Agreements may play a significant role. In particular, treaties with Trinidad & Tobago, such as the Delimitation Treaty of 1990 and the Framework Treaty on the Unitisation of Hydrocarbons Reservoirs of March 2007. The resulting Unitisation Agreements (the first was signed in 2013) cover three gas reservoirs located in common frontier areas: Loran-Manatee Field is the largest, with an estimated 10.25 tcf of reserves. Venezuela holds a 73.75% ownership interest, and Trinidad & Tobago holds 26.25%. Ownership of the Cocuina-Manakin Field, with an estimated 740 bcf of reserves, is 66% held by Trinidad & Tobago and 34% held by Venezuela. The Dorado-Kapot Field has an estimated 310 bcf of reserves and is 84.1% held by Trinidad & Tobago and 15.9% held by Venezuela.

Other bilateral treaty obligations can also impact regulatory policy. For example, the friendship and bilateral treaties with the Russian Federation has not only allowed for the financing of different projects and identification of a common agenda between Venezuela and Russia, but has also allowed for the setting up of terms and conditions for certain *Empresa Mixta* projects which would otherwise be provided in *Asamblea Nacional* approvals. Furthermore, bilateral treaties with the People's Republic of China ("PRC") have resulted in financing and significant commitment of oil output to the PRC as well as projects for converting debt into investment.

With regards to gas, Venezuela is a member of the Gas Exporting Countries Forum ("GECF"), an international governmental organisation created as a forum for exchanging experience and information among its member countries. GECF aims at gathering some of the world's leading gas producers, with the objective of increasing the level of coordination and collaboration among member countries. No production or export commitments by its members are covered or envisaged under the GECF's current framework.

13 Dispute Resolution

13.1 Provide a brief overview of compulsory dispute resolution procedures (statutory or otherwise) applying to the oil and natural gas sector (if any), including procedures applying in the context of disputes between the applicable Government authority/regulator and: participants in relation to oil and natural gas development; transportation pipeline and associated infrastructure owners or users in relation to the transportation, processing or storage of natural gas; downstream oil infrastructure owners or users; and distribution network owners or users in relation to the distribution/transmission of natural gas.

Article 24, ordinal b of the LOHG allows for arbitration as a means of dispute resolution in the granting of gas E&P licences if and when the Government and the licensee so agree (Article 19 of the LOHG). In case there is a lack of an agreement, any dispute which arises thereof is submitted to litigation before the local courts.

Licences granted to date establish arbitration as an alternative for dispute resolution, but the same may be rendered useless as the provision under the licences require parties to agree to arbitration and its terms and conditions in the event of a dispute; hence, there is no set commitment to advance with the same. Nevertheless, if the parties so agree, the award shall be final and binding.

A similar treatment (i.e. arbitration as a means of dispute resolution if and when the Government and the permit holder so agree; and if there is no agreement, any dispute is submitted to court litigation) is to be afforded to permits or consents associated with transportation, distribution, storage, marketing and processing (Article 27 of the LOH).

A similar regime applies under the LOH to controversies arising under *Empresas Mixtas* agreements.

13.2 Is your jurisdiction a signatory to, and has it duly ratified into domestic legislation: the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards; and/or the Convention on the Settlement of Investment Disputes between States and Nationals of Other States ("ICSID")?

Venezuela is a signatory to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, the same was duly ratified and remains enforceable.

On January 24, 2012, Venezuela denounced the Convention on the Settlement of Investment Disputes between States and Nationals of other States. Venezuela joined Ecuador and Bolivia as the only countries that have officially separated from the International Centre for Settlement of Investment Disputes ("ICSID"). Despite this, Venezuela has an extensive bilateral investment treaty network in place under most of which ICSID or alternative institutional arbitration means (e.g. *ad hoc* panels or UNCITRAL) can be pursued whether Venezuela is a party or not to the ICSID Convention.

13.3 Is there any special difficulty (whether as a matter of law or practice) in litigating, or seeking to enforce judgments or awards, against Government authorities or State organs (including any immunity)?

Historically, litigating in Venezuela against the Government or its instrumentalities has been a painful and mostly fruitless process. Litigation is slow and there are certain financial privileges and procedural prerogatives which apply to the Government (Ministries) and certain Government instrumentalities which may delay or even prevent the possibility to successfully advance litigation before the Venezuelan courts against the Government or its entities, or to effectively collect an award in Venezuela. In addition, there is a natural bias in favour of the Government and Government entities, as most judges' appointments are interim.

Enforcement of foreign decisions and arbitral awards has been recognised (albeit theoretically) by the Supreme Tribunal of Justice in the Constitutional Chamber, including ICSID panels' awards. To be sure, Venezuela enjoys immunity of jurisdiction unless it waives the same. While its instrumentalities are not subject to immunity of jurisdiction, the LOH and LOHG provide for application of local jurisdiction unless the parties have decided to submit to arbitration. It remains to be seen what will happen if there is a request for enforcement.

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13.4 Have there been instances in the oil and natural gas sector when foreign corporations have successfully obtained judgments or awards against Government authorities or State organs pursuant to litigation before domestic courts?

Yes, in some instances oil and natural gas investors have pursued and successfully obtained judgments from local courts. During the 90s and the past decade, some significant tax and royalty litigation was carried out with mixed results. The experience has been different in the case of litigation against the State or its instrumentalities on commercial matters (e.g. price setting or compliance by PDVSA Gas with a supply agreement) where there is a significant bias in favour of the Government and its instrumentalities.

14 Updates

14.1 Please provide, in no more than 300 words, a summary of any new cases, trends and developments in Oil and Gas Regulation Law in your jurisdiction.

The main developments in Venezuela are related with the financial stability of PDVSA and its ability to meet its financial obligations, as well as with the issuing of sanctions by the U.S. Government against the Venezuelan Government and its instrumentalities (including PDVSA and its affiliates).

With regards to PDVSA's financial stability, international oil prices have recovered throughout 2017, but production and exports have been missing the targets identified in Venezuela's government mid-term plan ("*Plan de la Patria*"), and the same continued to fall during the past three years (OPEC identifies production at 1,938 mbd for June 2017), with a bleak forecast in light of the slowing of operations by main drillers Schlumberger and Halliburton. A look at PDVSA financials for 2016 show a decline in net income of 88.7% to $828 million in 2016 due to the decline in production and low prices, under which PDVSA will not be able to cope with needed investments in its own operations or in the cash-calls required by its participation in *Empresas Mixtas*, which is likely to further accelerate the loss in production.

In addition, in August 2017, the U.S. issued sanctions against high-level government officials as well as restricting the ability for U.S. citizens and companies to enter into financial transactions with PDVSA and its affiliates. The imposed sanctions resulted in limitations related to U.S. customers as well as certain services providers since, in many cases, payment conditions agreed with PDVSA can be recharacterised as financial transactions. The sanctions will likely generate additional restraints to the already limited ability of the Venezuelan Government to restructure its own debt and that of PDVSA.

On the other hand, Russia's Rosneft seems to be poised to close a deal with the Venezuelan Government for the development of two offshore Paria gas fields (*Patao* and *Mejillones*) through a licence. The two fields hold a combined 180 bcm of natural gas. If closed, the project is likely to be the largest gas project in place, together with the already producing *Cardón IV* project.

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He has acted as counsel to international oil companies in projects in Venezuela on regulatory matters, as well as corporate and tax structuring for ventures under former operating agreements and association agreements, as well as for the setting up and operation of *Empresas Mixtas* and gas licences. He has also advised sponsors on project and corporate financing, including the set-up of the local financial arrangements and security packages and the review and implementation of the financial arrangements in Venezuela, and follow-up financial completion. Juan Carlos has also advised oil companies on features in relation to ICSID arbitration related to expropriation of their oil assets or interests in Venezuela.

Juan Carlos received his J.D. from *Universidad Católica Andrés Bello* in 1991, his LL.M. from *Universidad Católica Andrés Bello* in 1993, and his LL.M. from New York University in 2003. He is a faculty member of *Universidad Católica Andrés Bello*.

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She has ample experience participating in: finance projects for both private and public entities; mergers; investment structuring and protection; advice regarding foreign exchange matters; and legal advice regarding taxation, both national and municipal, with particular experience in the area of international taxation.

Valentina has in-depth knowledge of the energy sector, with experience: advising gas exploration projects under the licence system; in the negotiation of mixed companies for the production of hydrocarbons; negotiating and advising in Engineering, Procurement and Construction Contracts (EPC) for the construction, commissioning and/or modernisation of electric and petrochemical plants; advising contractors of the oil industry in providing services inherent in onshore and offshore oil production; and advising in international arbitration and negotiation of disputes arising under Venezuelan law.

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Furthermore, the firm has developed its practice in different areas, such as: administrative law; antitrust; arbitration; mediation and reconciliation; aviation; banks and financial institutions; capital markets; consumer protection; commercial and corporate; energy; the environment; expropriations and nationalisations; family businesses; finance; financial law; foundations and non-profit organisations; insurance; litigation; maritime and transportation; media and telecommunications; mergers and acquisitions; mining; pharmacy and biotechnology; project finance; real estate and construction; taxation; and planning, among others.

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