EI SourceBook

GOOD PRACTICE NOTE

(UPSTREAM) NATURAL GAS

2011

GOOD PRACTICE NOTE ON (UPSTREAM) NATURAL GAS

A GUIDANCE NOTE

To Complement The

EI Source Book

Note Prepared For

University of Dundee

By Honoré Le Leuch

21 September 2011

Notice

This document was prepared by Honoré Le Leuch (HLC Energies) for the sole use of The **EI Source Book** under preparation by The University of Dundee for the World Bank.

This task was performed under a subcontract entered into with the University of Dundee.

The document is submitted on the basis of the confidentiality clause provided for under the above subcontract.

For any comment or suggestion, the author may be contacted by email at hleleuch@gmail.com

Copyright

Table of Contents

Abbreviations and Acronyms

AIPN	Association of International Petroleum Negotiators
API	American Petroleum Institute
bbl	Barrel
Bcm	Billion cubic meters
bcpd	Barrels of condensate per day
bpd or b/d	Barrels per day
Boe	Barrel of oil equivalent (including oil, natural gas and gas liquids)
BOOT	Build, own, operate and transfer
Btu	British thermal unit
CBM	Coal bed methane
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage (or sequestration)
CDM	Clean Development Mechanism
CGR	Condensate/gas ratio
CNG	Compressed natural gas
CSR	Corporate social responsibilities
CT	Corporate tax
DCF	Discounted cash flow
DD&A	Depreciation, Depletion, and Amortization
DMO	Domestic Market Obligation
DOE	U.S. Department of Energy
DPSA	Development and production sharing agreement
ECT	Energy Charter Treaty
EOR	Enhanced oil recovery
E&P	Exploration and production, also called upstream
EIA	Environmental Impact Assessment
EITI	Extractive Industries Transparency Initiative
EPSA or EPSC	Exploration and production sharing agreement or contract
ESIA	Environmental and Social (or socio-economic) Impact Assessment
EIS	Environment Impact Statement
EU	European Union
FEED	Front end engineering and design
FERC	U.S. Federal Energy Regulatory Commission
FID	Final investment decision
FMV	Fair Market Value
GDA	Gas development agreement
GGFR	Global Gas Flaring Reduction Public Private Partnership initiated by the World Bank
GCV	Gross calorific value
GHV	Gross heating value
GHG	Greenhouse gases
GJ	Gigajoules
GOR	Gas/oil ratio
GTA	Gas transportation agreement
GSA	Gas sales agreement or gas sales and purchase agreement
GW	Gigawatt
GTL	Gas to liquids
HSE	Health, Safety and Environment
HSSE	Health, Safety, Security and Environment
IAS	International Accounting Standards

IEA	International Energy Agency
IMF	International Monetary Fund
IOC	International oil and gas company (including integrated “majors” and “independents” of the private sector, but excluding NOCs)
IOR	Improved oil recovery
IRR	Internal rate-of-return (similar to ROR or ROI)
JOA	Joint operating agreement
JV	Joint venture, either an unincorporated JV or an incorporated JV
LCM	Lower of Cost or Market
LDC	Local distribution company
LPG	Liquefied petroleum gas
LNG	Liquefied natural gas
Mcf	Thousand cubic feet of gas as measured at specified pressure and temperature conditions
MMBtu	One million Btu
MMcfd	One million cubic feet of gas per day as measured at specified pressure and temperature conditions
MMtpa	Million metric tonne per year
Mscf	Thousand cubic feet of gas as measured at standard conditions
MMW	Megawatt
NEB	National Energy Board of Canada
NGL	Natural gas liquids, including field and plant condensate
NGO	Non-governmental organization
NOC	National oil and gas company which is fully owned or primarily owned and controlled by a State
NPD	Norwegian Petroleum Directorate
Ofgem	The UK Office of Gas and Electricity Markets
OPEC	Organization of Petroleum Exporting Countries
OECD	Organization for Economic Cooperation and Development
OpCo	Operating company
PSA (or PSC)	Production sharing agreement (or contract)
ROI	Return on investment
ROR	Rate-of-return
ROW	Right of Way
SEC	U.S. Securities and Exchange Commission
SIA	Social Impact Assessment
SIAP	Social Impact Assessment Plan
SPE	Society of Petroleum Engineers
SWF	Sovereign wealth fund
Tcf	Trillion cubic feet
Tcm	Trillion cubic meters
TOP	take or pay
TPA	Third party access
UE	European Union
WB	The World Bank

Summary

This report entitled *Good Practice Note on (Upstream) Natural Gas* was prepared as a third-party reference document to the ***Extractive Industries (EI) Source Book***.

The importance of natural gas in the world, both in developed and developing countries, is increasing in the transition to a low carbon world. The growth of the world gas production, consumption and exports was high in the last decades and this trend will continue because conventional gas resources are quite large, unconventional gas is more and more exploited and gas has the advantage of a lower carbon content that other fuels. However, gas developments may only occur if countries adopt the appropriate policies from the “wellhead to the burner tip” for encouraging both gas production and its uses.

The objectives of this *Guidance* are **to identify present and desired good or best practice with respect to natural gas exploration, development and production (“upstream”) activities**, paying particular attention to: upstream gas policy, strategy, licensing; legal, contractual and regulatory requirements; and fiscal regimes. Insights on the key requirements for *downstream* gas activities beyond gas production are presented as gas can only be exploited if it is sold to end-users willing to pay the appropriate price for investing in the entire supply chain.

After an overview of the critical factors for designing country gas strategies and policies, the possible uses of natural gas, in particular for power generation, and the structure of the gas industry along the entire supply chain, this document addresses essential upstream gas strategy and policy decisions for developing countries, the options available and good practice in the upstream sector as related to legislation, fiscal and regulatory regimes, and contracts. Selected examples of practice followed by gas countries in terms of legal, regulatory, fiscal and contractual frameworks applied to the gas activities are enlightened in the document with the details provided in Appendices.

Gas policy objectives

All the gas resources are not declared as commercial projects. Difficulties for reaching gas commerciality occur in particular in countries where no appropriate domestic gas infrastructure and markets already exist, which is often the case in developing countries. Commerciality requires, first, the availability of sufficient reserves and the decision of the producer to develop them, second, the identification of viable long term gas markets and motivated buyers, locally and/or abroad when exports are justified in the country interest, and, third, finding ways for building the local processing and transmission facilities. Moreover, prioritization between the possible gas markets and uses has to be decided in order to obtain the highest possible added value for both the country and its investors.

The two key objectives of gas policies are to encourage the exploration and production (upstream) activities in the country under a fair fiscal regime, and to actively promote the domestic uses for the produced gas by establishing the adequate conditions allowing the private and public sector to invest in the local infrastructure necessary for gas transportation and distribution to the main end-users. They are many ways to achieve these objectives which are detailed in the Guidance. Thus, regulatory measures may facilitate the commerciality of small to medium size gas discoveries located in the same region but made by several investors, when their joint exploitation by aggregating the reserves as set forth in the regulation may render the total project viable while otherwise the development of individual fields would be uneconomic.

Critical technical and economic considerations: differences with oil

Gas may be produced in two forms: as associated gas produced with oil from an “oil field” (around 30% of the total world gas production) or as “nonassociated gas” extracted from “gas fields” or “gas condensate fields”. Any upstream gas policy, legislation, taxation, regulation and contracts must contain specific provisions dealing with each type of gas. For example, flaring of associated gas for new oil fields should be prohibited except in very special circumstances, and priority use of associated gas when produced versus nonassociated gas should be favoured.

Gas is not oil from for technical and economic reasons even if both are defined as “petroleum” under legislation. Indeed, they are many differences. Thus, on a calorific value’s equivalence, gas price is generally lower than oil, due *inter alia* to the fuel inter-competition between gas and cheaper coal; gas processing and transportation costs are greater than for oil; gas field development projects require often the prior negotiation of long term gas sale agreements with buyers, including the gas price determination and indexation formula, which may delay for several years the decision for development. As a consequence of the relative higher costs, the profitability of a gas project could be lower than for oil project of similar size should the same tax provisions apply, which requires the introduction in the legislation of fiscal i*ncentives* for gas.

The type of domestic gas uses and the possibility of building export projects greatly depend on the estimated amount of available gas reserves in the country. Thus, liquefied natural gas (LNG) export projects can only be considered when significantly large reserves exist while local gas-fired power plants needs relatively small reserves.

Key Principles for Good Practice and examples

Many Guidelines are presented in the document which should be introduced in petroleum legislation, taxation, regulation and contracts. They are designed for taking into account the specificities of gas versus oil and fostering gas developments in a country.

Thus, the oil and gas (petroleum) law should authorize in case of gas discoveries longer appraisal periods, and production periods, than for oil discoveries, with the right to grant a specific “gas retention license” for assessing the viability of a gas discovery and finding gas buyers. The law should provide for mandatory joint development and exploitation of gas discoveries between several licensees when such system renders viable gas projects otherwise non commercial. The law should define the specific fiscal incentives for promoting gas activities and the principles for gas pricing as well as the specific provisions for unconventional gas.

The law should also state the priorities for gas uses, in particular between viable domestic and export uses, and provide for gas re-injection in reservoirs when justified for increasing oil and condensate recovery. The law may also introduce, when the respective planned gas supply and demand of the country so require the principle of constituting minimum national gas reserves allocated to domestic requirements and set conditions for authorizing exports, especially in highly populated countries with potentially limited gas resources in relation to a growing gas demand.

Many examples of successful and less successful countries’ gas strategies and policies are highlighted under the document along with the difficulties which may be encountered when implementing gas policies.

1 INTRODUCTION & BACKGROUND

1.1 Introduction

This report entitled *Good Practice Note on (Upstream) Natural Gas* was prepared as a third-party reference document to the ***Extractive Industries (EI) Source Book***.

The objectives of this *Good Practice Note on (Upstream) Natural Gas* are **to identify present and desired good or best practice with respect to natural gas exploration, development and production ("upstream") activities**, paying particular attention to: upstream gas policies, strategy, licensing; legal, contractual and regulatory (oversight) requirements; and fiscal regimes. This document is not a gas handbook as the aim is to provide a short good practice note that identifies common/good practice with respect to legal, contractual, regulatory and fiscal frameworks for upstream natural gas investment and operations.

After an overview of the critical factors concerning gas policies, the possible uses of natural gas and the structure of the gas industry, this document addresses essential upstream gas strategy and policy decisions for developing countries, the options available and good practice in the upstream sector as related to legislation, contractual provisions, fiscal and regulatory regimes.

The possible options for achieving the necessary "monetization" of discovered gas resources are briefly analyzed, including appropriate upstream development incentives when justified. Moreover, a description of the various segments of the entire *gas value chain* from the "wellhead to burner tip" is presented along with the respective policy considerations, having in mind that the focus of this document is on upstream issues. Selected examples of international practice followed by gas countries are briefly enlightened with details provided in Appendices.

A summary discussion of the key requirements for *downstream* gas activities beyond gas production is presented as gas can only be exploited if it is sold to end-users willing to pay the appropriate price.

In the future, it is planned that under the next phase of the *EI Source Book* project more detailed and comprehensive guidance on upstream and downstream natural gas will be developed.

The author worked in close coordination with Professor Peter Cameron and Dr. Charles McPherson of University of Dundee and benefitted from the insights of Alan Cunninghan, Michael Levitsky and David Sandley of the World Bank. He thanks them for their valuable advice.

1.2 Background on natural gas

The importance of natural gas in the world, both in developed and developing countries is increasing in the transition to a low carbon world. Natural gas has been found in substantial quantities in many developing countries, both as a by-product (named "associated gas") of the search for oil or in nonassociated gas fields. Focused exploration for natural gas could significantly increase reserves. The importance of this lies in the fact that natural gas has enormous potential to contribute to sustainable and diversified development in the countries where it is found. Major deposits of gas may justify its export by pipeline or in the form of liquefied natural gas (LNG), thus generating attractive revenue, which can be used for development.

More importantly, in many cases gas delivered to the domestic market can directly promote development by fuelling electric power plants and a wide range of industrial processes and activities. This encourages desirable economic diversification, and, in turn, increases opportunities for local participation in the economy.

Unfortunately, both the exploration for natural gas and its development are all too often hampered by the absence of an appropriate policy, legal, contractual and fiscal framework. The problem is almost invariably compounded by a lack of essential physical infrastructure to transport, process, store and use gas, of adequate legal and regulatory frameworks for the commercialization of gas, and finally by the questionable viability of end-user markets, particularly respecting price and ability to pay.

Far more than oil, promotion of natural gas depends on **attention to the entire gas value chain** from exploration and development through to the final market. While not unique in importance, exploration and development terms and conditions are nevertheless a critical and indispensable part of this process.

Long neglected, a range of appropriate frameworks for gas exploration and development is now emerging to guide good practice. Their wider recognition and dissemination can be expected to produce valuable payoffs in terms of natural gas and economic development.

2 CRITICAL FACTORS FOR DESIGNING GAS STRATEGY AND POLICY

2.1 Introduction

Each country has to decide on its own gas policy for upstream and downstream activities taking into account its specificities and benefitting from the experience gained by other countries. The optimum gas strategy and policy for a country depends on many factors, mainly related to the amount and type of already discovered and prospective domestic gas resources, the stage of development of the local natural gas industry, and the potential markets for selling the gas either in the country or abroad. Considering the world long-term outlook for gas is also paramount for policy decisions.

There are major differences between oil and natural gas activities and economics. First, gas generally requires special marketing arrangements with customers on a long-term basis while oil can be sold freely on the international market including on a short time basis. Even if more gas is progressively sold on the spot markets, especially liquefied natural gas (LNG), the development of gas fields and the building of gas processing and transportation is often contingent to the signing of long-term gas purchase agreements. Second, gas transportation costs to the end-users are higher than for oil due to their respective physical characteristics, being gaseous versus liquid. Third, gas is often sold at a price lower than the equivalent calorific value of oil for encouraging new gas development projects and the use of gas which is competing with other fuels, especially coal.

The following basic questions have to be addressed before a country decides on its gas strategy:

- How much gas is available in the country?
- What are the types and composition of the gas produced in the country?
- What are the potential markets for selling the gas at the highest added value?
- How the local gas industry can be organized and what is the impact of the global outlook for gas?

Many specific measurement units are used in the gas industry and should be known. Insights on main gas units and relevant conversion factors are given in **Appendix 7.1** to this document.[1]

A great care should be given to the definitions in any gas documents and agreements to prevent misinterpretations of legal, regulatory, fiscal and contractual documents related to gas. Such definitions should be clear, precise and accurate as illustrated in **Appendix 7.2**.

2.2 Estimation of available gas: reserves and resources

The first action to be taken by a country for deciding on its gas strategy is to assess the range of its estimated gas reserves and resources. Gas reserves and gas resources correspond to quite different concepts in the industry and therefore have to be correctly used

[1] Anglo-Saxon or metric system units may be used as provided for in the country regulations. Gas is generally measured in *volume* and sold on the basis of its *gross calorific value* or *gross heating value* (GHV), often expressed in MMBtu (million Btu) under the Anglo-Saxon units system, or in Gigajoules or MWh under the metric system. The calorific value of a gas volume depends on its composition and generally varies from 0.95 to 1.1 MMBtu/Mscf.

for preparing reliable gas feasibility and markets studies. The volumes of available gas are classified as gas reserves or resources depending on the degree of uncertainty on the estimated volumes and a risk element, the chance of discovery. Several definitions and classification systems have been published in the world to evaluate the volumes of gas which may be produced and sold in the future at the level of a field, a region or a country.

The most common rules for estimating and classifying gas reserves and resources are highlighted in **Appendix 7.3** to this Guidance. Thus, **Reserves** are those quantities of petroleum anticipated to be **commercially recoverable** by application of development projects to known accumulations from a given date forward under defined conditions. **Resources** correspond to larger volumes as they also include undiscovered gas. **Reserves must further satisfy four criteria***: "they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied."* Reserves are further categorized as *proved, probable* or *possible reserves* in accordance with the level of certainty associated with the estimates.

For gas discoveries the key question for a country and an investor is when contingent resources already discovered can be classified as reserves. Such date is related to the degree of certainty that (1) a *commercial gas development* exists and (2) the decision to carry out such development project is taken–what is called the *final investment decision* (FID)–or is planned to be taken in a relatively short period. Criteria for classifying gas as *proved reserves* are (1) that the FID was taken and (2) that the host government has already approved the gas development under the applicable regulatory framework.

The reserves for a gas field generally consist of two estimated volumes per reserves category, first for *dry gas* and second for *natural gas liquids (NGLs)* extracted from wet gas and consisting of condensates and liquefied petroleum products (LPGs).

In conclusion and in accordance with good petroleum practice, **Reserves only exist for gas when the commercial viability of a given gas development project is demonstrated** by appropriate technical and economic studies and a decision for their development is taken or envisaged shortly. Such a decision requires to have already identified the commercial uses for the gas to be developed. Otherwise the gas should be only classified as Resources.

2.3 Type and composition of available gas

Knowing the amount of reserves is not sufficient as **natural gas may exist in underground reservoirs in two physical types: associated or nonassociated gas,** each one having its own legal and regulatory framework. Moreover, the gas composition varies from gas to gas with an impact on the selling price.

Associated gas corresponds to natural gas that occurs with crude oil, either as free gas located above reservoir oil (*Gas Cap Gas*), or in solution dissolved in reservoir oil (*Solution Gas*) and liberated from solution by reduction in pressure and temperature. From a legal and regulatory point of view, the reservoir containing both oil and associated gas is generally **classified as an *oil field***. On average, near 30% of the worldwide gas production consists of associated gas and this share is decreasing.

Most of the energy of the gas cap is required for maximizing oil recovery. Therefore, under energy conservation good practice, associated gas production from an oil reservoir must be carefully planned and monitored before deciding to sell the associated gas. In many cases r*e-injection* in the reservoir–through gas re-injection wells–of the gas extracted when producing oil, instead of the immediate sales of such gas, should be imposed for pressure maintenance, or to prevent gas flaring or venting, as explained in Section 3.1.2.

Nonassociated gas consists of natural gas found in a natural reservoir that does not contain crude oil. From a legal and regulatory point of view, the reservoir containing nonassociated gas is generally **classified as a *gas field*** or when sufficient condensate is present as a ***gas condensate field***.

Liquid hydrocarbons components may generally be extracted from nonassociated gas, as from associated gas, after an appropriate surface separation and processing with the economic consequence of increasing the global gas value. The most common liquid component is called *condensate* or *condensate lease* or *natural gasoline*, a form of very light oil having a specific gravity higher than 40° API. The *condensate/gas ratio* (GCR) may vary from about 10 to 100 bbl/MMcfd.

Under good reservoir engineering practice, gas re-injection of the produced nonassociated gas after extraction at the surface of the liquid components from the nonassociated gas, a process called *gas cycling*, may be justified and imposed during the first phase of production of a **gas condensate field**. This process allows maximizing the recovery of liquids from the rich gas and prevents the deposition of a liquid fraction in the underground reservoir by a too rapid pressure drop. The field development plan should address this issue before authorizing the commercial sale of nonassociated gas from gas condensate fields.

The composition of natural gas varies from reservoir to reservoir, and may also vary during the production period, in particular for the petroleum liquid concentrations. **The calorific value or heating value** of a given volume of natural gas depends on its composition, and therefore the selling price for a unit of volume of gas. Moreover, the type of processing to be performed before transporting and selling the gas depends on the gas composition.

2.4 Conventional and unconventional natural gas

Conventional natural gas is the gas traditionally exploited in the world. It corresponds to gas extracted from porous underground reservoirs in which the gas was trapped after its expulsion and migration from the geologic formation (consisting mainly of shales and called *source rock*) where it was generated by conversion of organic matter.

During the two last decades, more and more **unconventional natural gas** were commercially exploited for the first time, in particular in North America, resulting in a major change on the gas markets considered as a “revolution” by the US gas industry.[2] Many other countries also hold significant unconventional gas resources. Unconventional gas may consist of three categories of gas depending on its origin:

- *The so-called “tight gas”*, similar to conventional gas but originating from *reservoirs* having very low porosity and permeability, in particular from deep reservoirs. Gas production from tight reservoirs requires the hydraulic fracturing of the reservoir rock. Such production only became economic recently as a result of the use of horizontal wells and other technological progress.
- *The “shale gas”* which, at the difference of conventional gas, is gas directly extracted from the *source rocks*, often shales, where it was generated. Due to the extremely

[2] In the US, the share of shale gas and CBM in the total gas production could rapidly increase from 17% in 2008 to 34% in 2030.

low porosity and permeability of shales, the production of shale gas requires the hydraulic fracturing of the rock, for the same reasons as for tight gas

- *The "coalbed methane"* (CBM)–also called "coal-seal methane" (CSM) in Australia or "coal natural gas" (CNG)–which corresponds to gas existing in coal beds and extracted by drilling wells.

In many countries, the existing legal, regulatory and contractual frameworks dealing with conventional gas also govern unconventional gas. It is however recommended to review the existing gas provisions of the country in order to introduce **specific amendments for unconventional gas activities** as highlighted in Section 5.4.

2.5 Possible uses and markets for the available gas

Gas produced in a country may be used either locally or exported in the world, in both cases under sale and purchase agreements entered into with the interested buyers. Gas exports generally require an approval from the exporting country authorities and therefore this issue is a critical component of the gas policy. For energy supply security reasons countries having large domestic markets may only authorize gas exports when a sufficient threshold of reserves has been reached corresponding to the planned local gas demand requirements in the long run.

In 2009 on average around 70 percent of the produced gas is consumed domestically and only 30 percent is exported, a proportion considerably lesser than for oil which amounts to 66 percent. The main reasons for explaining the considerably lower share of exports for gas than for oil are that (1) gas required for its exports more costly transportation infrastructure facilities than oil, and (2) local gas uses when they exist in large volumes in the country may have a greater added value for the country than exporting gas under costly export schemes. Gas exports are made either by using dedicated transnational pipelines or by shipping gas as liquefied natural gas (LNG) in LNG-carriers. Today **around two thirds of exported gas is transported by pipeline and one third as LNG**. The LNG proportion is planned to continue to rise up to 40% in the next 25 years, and is even much higher in developing countries. Details on world LNG markets are given in Appendix 8.4.

Locally, gas may be used for many purposes, mostly as a fuel competing with other fuels, such as coal, fuel oil or gas oil, or as a feedstock in petrochemistry. The possible gas uses are detailed in Section 3.1.1 which highlights that the demand for gas in most countries is in priority for power generation, and then in the industrial, commercial, residential and transportation sectors.

Careful attention should be paid by a producing country in identifying and promoting the domestic gas uses. If the country does not focus on using gas locally, by implementing the appropriate legal, fiscal and regulatory frameworks, the necessary investments may not be carried out on time by the public and private sectors.

The type of local gas uses and export projects greatly depends on the estimated amount of available gas reserves in the country. Table 1 displays the approximate minimum reserves generally necessary to economically justify a given gas utilization project, showing that **an LNG export project can only be considered when significantly large reserves exist while a local power plant needs relatively small reserves**. The new concept of floating LNG plants just introduced will however reduce the minimum reserves threshold for justifying an LNG project.

Table 1 Required reserves for commercial gas uses

Possible use and capacity	Minimum required gas reserves (1)	
	In Tcf	In Bcm
LNG plant (4 MMtpa) (2)	4-6	120-160
Power plant (600 MMW)	0.6	16
Power plant (300 MMW)	0.3	8
Ammonia/urea plant (1,500 t/d)	0.3	8

(1) The gas reserves may consist of existing *proved and probable* reserves categories as they are defined in the industry.
(2) An LNG production of 1 MMtpa requires approximately 1 TCF over 20 years. The reserves allocated to the plant have to be significantly higher as the production continues beyond the initial 20-year period.
(3) The required gas reserves depend, first, on the type and efficiency of the gas turbines (from around 40% for open-cycle gas turbine (OCGT) to near 60% for combined-cycle gas turbines (CCGT), when expressed on a net heating value; and second on the type of use of the power plant either for peak load or base load.

As a consequence the country strategy for selecting gas utilization projects should be directly based at a given date on the combined size of the existing estimated reserves complemented by the most likely gas discoveries that could be made within a reasonable time frame.

2.6 Organization of the domestic gas sectors and legal consequence

The gas policy designed by a country should deal with all the activities from the search for gas up to the end-users. Such activities are of different nature and risk levels and govern by different laws and contracts or licenses. Table 2 displays an overview of the main sectors constituting the gas supply chainu the natural gas industry, the activities, the actors and the main legal and regulatory frameworks and type of contracts applicable per sector.

The Guidance will address in the following Sections 3 to 7 each segment of the supply chain. A successful gas country policy must adequately foster investments at each stage of the supply chain from exploration to gas utilization.

2.7 Global gas outlook: the announced "golden age" for gas

Appendix 7.4 presents insights on the exceptional growth of the gas production, consumption and exports in the last decades. Thus, the world gas consumption (the *net* marketed production) *doubled* between 1980 and 2009, rising from around 1,450 Bcm to 3,100 Bcm (110 Tcf).[3] **The gas consumption growth was considerably higher in developing countries, increasing from 170 Bcm in 1980 to over 900 Bcm in 2008**, with a share in the world consumption varying from 12 % to 32 %. The gas exports from developing countries to the developed world jumped from 21 Bcm in 1980 to 225 Bcm in 2008. In developing countries which possess large gas resources and reserves more and more gas is produced, consumed locally in a large proportion and for the balance exported

[3] The 2009 equivalent *gross production* amounts to 3,800 Bcm (134 Tcf) when the quantities of re-injected gas, flared gas and gas used in operations are added to the marketed production.

Table 2: Overview of the natural gas industry

Type of Activity among the Gas Value Chain	Main Actors	Applicable Law & Regulation	Applicable Contracts & Licences
Exploration & Production (Upstream) -including field processing & gathering pipelines when related to a gas field development	Oil & Gas Companies Producers (IOCs, NOCs)	The Oil & Gas Law (1), and related regulations	E&P Petroleum Agreements Gas development Agreements (GDAs)
Supply: purchase and sale of gas to other suppliers and consumers, to an LNG plant, etc.	Suppliers Marketers Exporters Importers	Depending on the place of the supply activity The Gas Law often applies to supplies for end-users	Gas Sales Agreements (GSAs) Gas Export or Import Licences Gas Supply Licence (when applicable)
Transportation/Transmission (Downstream) -including pipeline networks, common central processing plants	Transporters Shippers Pipeline Companies	The Gas Law	Gas Transportation Agreements (GTAs) Transportation Licences/Pipeline Licences
LNG plant and terminal. **Re-gasification terminal**.	Generally, Oil & Gas Companies	Depending on the place of the plant and terminal	
Storage (Downstream): Underground gas storage	Gas Storage Companies	The Gas Law	Storage Licence
Distribution (Downstream): -distribution and sale to consumers (wholesale or retail trade)	Distribution Companies, Local Distribution Companies (LDCs)	The Gas Law	Distribution Network Licence (approval of service terms and conditions, tariffs…)
Consumption of natural gas (Downstream)	Gas Consumers and End-Users	The Gas Law	Variable, depending on the use (e.g. a Generation Licence for power plants)

(1) The expression "The Oil & Gas Law" used in the above Table means the so-called *Petroleum Exploration and Production Law* which applies both to oil and gas upstream operations. "The Gas Law" refers to the *Gas Law* or similar legal instruments covering the gas activities other than the upstream ones.

In a lower carbon energy world, demand for gas will continue to rise, especially if carbon r taxes are introduced on fuels, for example on the fuels used in power generation, in order to mitigate the climate change. Such taxes would grant to gas a higher competitive advantage because gas benefits from a lower carbon content that other fossil fuels, especially coal, and therefore would be subject to a lower carbon tax.

Most recent forecasts estimate that the gas demand by 2035 may reach 4,250-4,500 Bcm (150 to 160 Tcf), **an increase of 40 to 50% relative to 2008**, with a share of gas in the primary energy mix of 21 %. **Around 80% of the increase in gas demand may come from non-OECD countries,** namely from developing countries. **Reserves and resources** are sufficient to support such gas developments if the appropriate country gas policies are decided allowing the required investments to be made in a timely fashion in the entire gas supply chain.

3 THREE KEY CONCEPTS FOR SELECTING GAS STRATEGY: GAS MONETIZATION, VALUE CHAIN AND PRICING

3.1 Guidance on gas monetization: differences with oil

All the nonassociated gas discoveries and all the associated gas resources are not declared as commercial fields or projects. Such declaration requires, first, the availability of sufficient reserves and, second, the identification of commercial market(s) and motivated buyers ready to commit for purchasing the natural gas to be produced in the long run under a specific project. On the contrary, with oil the markets are functioning to buy any oil produced in the world and no specific long run commitments from buyers are required for deciding on a new oil field project.

Difficulties for reaching the stage of commerciality with gas occur in particular in the countries where no appropriate gas infrastructure and markets already exist, which is often the case in developing countries.[4] In such situations the priorities are **to monetize the discovered gas** by (1) identifying and developing viable long term gas markets and (2) finding ways for building the local processing and transmission facilities as well as export systems.

In addition, such monetization process should focus on the objective of obtaining the **highest possible added value** for the gas in order to economically justify its exploration, appraisal, development, production, transportation and its utilizations, domestically or abroad. Identification of the possible markets for gas has first to be performed by the country and its investors, even prior to promote or invest in gas exploration in a country, and then has to be periodically updated, considering the revision of the available gas resources and reserves. The ranking and selection of the most viable gas markets and uses between the identified possible options is conducted under a cost-benefit analysis. **Such prioritization between the gas markets and uses** may be different for private investors and for the country, showing the importance of studying the two points of views prior to deciding on the selection.

3.1.1 Possible gas uses for monetizing natural gas

Gas may be sold on the domestic market or exported. For selling natural gas within a country, they are many possible gas uses either as an energy source or a feedstock. The following summarizes the possible gas uses and the gas competitors.

As an energy source, natural gas competes with the other fuels, such as coal, petroleum products (fuel oil, gas oil, etc.), electricity, biogas, etc., depending on each actual use, sector and end-user. Gas may be used namely:

- *For power generation*. In many countries, this is the most frequent use of gas and generally the driver for starting monetizing the available gas in a country. Gas-fired plants are more and more preferred over coal and oil-fired plants as the gas has the great advantage of lower carbon emissions. Moreover, gas efficiency in power generation is today considerably higher by using combined-cycle gas turbines (CCGT) which may have a thermal efficiency up to near 60%, relative to the 34% efficiency of the open-cycling gas turbines (OCGT).

[4] In new gas zones, when the gas infrastructure are not yet built to connect gas discoveries to the markets, the already discovered gas is often called ***stranded gas*** until the date sufficient contingent resources are estimated to justify their monetization by the building of processing and transmission facilities. Many examples of stranded gas exist in the world, in developed countries (*e.g.* in the US Alaska, in Canadian Arctic, Russia, etc.) and in developing countries.

- *For the industrial sector*, such as in cement plants, steel plants, manufacturing, etc.
- *For the commercial sector*, such as heating for buildings.
- *For the residential (or domestic) sector*, such as heating houses or cooking.
- *In the transportation sector*, either for compressed natural gas (CNG) vehicles or by using liquefied natural gas in specially equipped vehicles or ships.

As a feedstock, natural gas is mostly used in the petrochemical industry, in competition with naphta, other petroleum products and fuels, for obtaining products such as methanol, ethanol, fertilizers (ammonia, urea), chemicals (for example, polystyrene, polyester…).

Gas may also be converted in a dedicated *gas-to-liquids (GTL) plant* into petroleum GTL products. Less than 10 GTL plants exist in the world and due to the change in the energy outlook, this promising use remains marginal except in Qatar and in a few others countries.

3.1.2 Gas monetization of associated gas: the reduction of gas flaring

Gas flaring of associated gas should not be authorized by governments, except in case of emergency for operational reasons or when no economic solutions exist. Indeed, flaring destroys the potential gas value when comparing to selling it for a commercial use and is also damaging the climate by adding about 400 million tonnes of CO_2 in annual emissions. Therefore, the legal and fiscal framework should prohibit regular flaring and impose a “no flaring option” in any new oil field development.

To prevent flaring, operators and the country should identify, on a case per case basis, the possible uses in the country of the associated gas simultaneously produced with oil and then select the most viable use(s). In the absence of any viable use, the associated gas should be temporarily re-injected in the oil reservoir–unless a technical reason prohibits it–as such gas is not lost and can be exploited and used at a later stage.

In countries holding both associated and nonassociated gas reserves governments may also help in flaring reduction **by organizing in priority at a given date the local use of the available associated gas** instead of nonassociated gas. This should be achieved by an adequate planning and coordination at the country level of new gas development projects and production plans, a strategy successfully achieved in several countries.

The existing **Clean Development Mechanism Program (CDM)** may also help in funding projects specifically designed to reduce associated gas flaring in developing countries.

Today, around 5% of the world gas production is still being flared or vented on existing producing oil fields corresponding to a volume of near 150 Bcm (or over 5 Tcf) per year, mostly in developing countries.[5] However many ongoing efforts are performed for reducing the volume of flared gas–leading to a reduction of 25% in the last 15 years. For new field development projects, government authorities are today reluctant to approve projects not based on the “no-flaring” development concept. A joint international initiative called “**the**

[5] The percentage of the annual gas production which is flared varies considerably from one country to another, from 0.3% in the US to over 25% in Nigeria, a record, where a new gas policy was decided in 2008 to reduce this considerable waste. Fewer than 20 countries account for more than 70 % of gas flaring, with five countries together (Russia, Nigeria, Iran, Iraq and Kazakhstan) flare near 60% of total gas flared in the world.

Global Gas Flaring Reduction” led by the World Bank was also launched in 2002 by governments and the industry to encourage flaring reduction projects, as presented in Box 1.

Box 1: Global Gas Flaring Reduction Partnership

In order to limit the amount of flared gas, the **Global Gas Flaring Reduction public-private partnership** (GGFR), a World Bank-led initiative, was launched at the World Summit on Sustainable Development in Johannesburg in August 2002.

The GGFR partnership is constituted of representatives from governments of 15 oil-producing countries, national oil companies and major international oil companies. The objectives of the GGFR partnership are to:

“*Overcome the barriers to reducing gas flaring by sharing global best practices and implementing country specific programs*”…

and “*facilitates and supports national efforts to use currently flared gas by promoting effective regulatory frameworks and tackling the constraints on gas utilization, such as insufficient infrastructure and poor access to local and international energy markets, particularly in developing countries.*

Poverty reduction is also an integral part of the GGFR program, which is developing concepts for how local communities close to the flaring sites can use natural gas and liquefied petroleum gas (LPG) that may otherwise be flared and wasted.

The program has already evaluated opportunities for small-scale gas utilization in several countries.”

Since its creation in 2002, the partnership has already achieved some significant results, including the endorsement by the majority of partners of the *Global Standard for gas flaring reduction* which was published in 2009 [see a summary of it in Box 4 of Section 4.2, the implementation of demonstration projects for associated gas utilization in eight countries, and the provision of assistance to Indonesia, Kazakhstan, Mexico, Nigeria, Qatar, Russia and other countries to reduce flaring to minimum levels, through increased collaboration between operators, the national oil company and the regulator.

3.1.3 Illustrative country cases on gas monetization strategy

Appendix 7.5 highlights six illustrative examples of gas monetization in developing countries presenting contrasting gas environments between Côte d’Ivoire, Equatorial Guinea, Yemen, Papua New Guinea, Egypt and Nigeria. Each country characteristics may be briefly summarized as follows:

- **Côte d’Ivoire** corresponds to the example of a country with only medium size gas reserves (around 1 Tcf) which successfully decided to promote their exploitation for supplying the local energy markets only, mainly to the power generation sector which was modernized by building new gas turbine plants for encouraging gas uses. Moreover, the exploitation of the commercial gas reserves consisting of associated and nonassociated gas was optimized to eliminate gas flaring by using in priority associated gas.
- **Equatorial Guinea**, where the large nonassociated reserves of a gas condensate were progressively monetized for exports, first by selling the condensate and other natural gas liquids while the gas was re-cycled in the reservoir waiting for its utilization at a later stage, second through a methanol plant and third by building an LNG plant. Now some gas is allocated to local needs. A possible extension of the LNG plant would reduce the amount of associated gas still flared in the country.
- **Yemen** is an example of an oil exporting country where the associated gas was mostly reinjected in oil fields during over 20 years, in the absence of commercial uses for gas. The gas pipeline and LNG plant built by new investors quite recently allow

now to export the associated and nonassociated gas as well as to supply gas to a power plant and other end-users but only to cover part of the local energy consumption.

- **Papua New Guinea,** where the first gas discoveries were made several decades ago, had over 10 Tcf of stranded gas located far from the markets and discovered by several distinct consortia. Recently, after an unitization of the reserves held by such consortia was agreed, the construction of a first major LNG project was decided for exporting the gas to three Asian countries under long-term contracts.
- **Egypt** represents today one of the most successful gas stories in the world demonstrating the impact of selecting the right country policy. The introduction of a drastically revised gas policy in the 1980s, with amendments to the legal, fiscal and contractual framework[6] designed to encourage gas exploration and to promote gas utilization in the country led to a series of discoveries holding quite large gas reserves. Today they are developed and in production by many operators for supplying mostly the local markets with the balance exported.
- **Nigeria**, on the contrary, is the example of a country with major gas resources which did not adopted the appropriate gas policy for a long time. The most obvious consequence is that today a large share of the associated gas is still flared while the country is not producing enough electricity, a use where the gas is so valuable. Only quite recently, in 2008, a modern gas policy was decided which may change this energy picture when implemented.

3.2 The gas value chain concept: from Upstream to Downstream

The gas supply chain is composed of two interconnected main segments: the *Upstream* and the *Downstream* sectors, because the gas produced must be sold to have a commercial project. Each sector is covered by specific legal, regulatory, fiscal and contractual regimes as the costs, risks, economics and business models of each sector are not comparable. Considering such economic differences, in most countries the oil and gas law only deals with the upstream sector–where among others the risks are the highest–while a specific gas law provides for the downstream sector.

The *Upstream* segment consists of all the exploration and production (E&P) activities required for finding, developing and producing gas. It also includes all the necessary activities for (1) gas processing in order to obtain gas and natural gas liquids *in marketable conditions* (such as the gas processing plants, separation and extraction units for obtaining condensates, natural gas liquids and LPGs), and (2) gas gathering (the flow lines and gathering pipeline systems) up to the *point of entry* into the transmission pipelines.

The *Downstream* segment includes all (1) the gas transmission system (the transmission pipeline networks, compression stations and related facilities), (2) the storage facilities, and (3) the gas distribution facilities (such as the gas pipeline distribution networks) in order to transmit the gas from the fields point of delivery up to the consumers and the gas end-users.

LNG projects are generally considered as pertaining to the *Downstream* sector or classified as a specific sector. In some cases they may be considered as integrated with an upstream project when the contractual scheme so provides.

In some regions, as in North America, the link between the Upstream and the Downstream sector, including the central processing plants and the transmission pipelines, is called the *Midstream sector*.

[6] The so-called “Egyptian gas clause” is detailed in Appendix 8.5.

The technical costs for each segment of the supply chain vary considerably in relation with the projects and depend strongly on the size, type and location of the field. The following orders of magnitude are only indicative for technical costs:

- *Upstream*: from 0.5 to 3 $/MMBtu, exceptionally up to 5 $/MMBtu or more. On a marginal basis, when considering associated gas as a by-product of oil, the cost would be lower, from 0.1 to 0.5 $/MMBtu as in the Middle East. Shale gas is often more expensive than conventional gas, depending on the conditions for its extraction, often in the $3-$7/MMBtu range.

  LNG operations would add from 2.5 to over 4 $/MMBtu to upstream costs for transformation of gas into LNG, LNG shipping and re-gasification, depending on the plant vintage, the size capacity and the distance for exports.

- *Pipeline transmission*: from $0.3/MMBtu to over $1/MMBtu per 1,000 km of pipeline, depending on the volume and location.

The total gas supply chain requires huge investments generally performed in close coordination by different investors. Thus, an estimate made by the International Energy Agency for the 2008-2030 period leads to a cumulative investment of over $5,100 billion for the world, with the following breakdown: 59% for *Upstream* (of which 53% in non-OECD countries), 31% for *Transmission/Distribution* and 10% for *LNG projects* (LNG plants, LNG tankers and LNG re-gasification terminals). This illustrates the challenges of any gas policy is encouraging timely investments in each segment of the supply chain, from upstream to transmission and distribution projects.

All the segments of the supply chain are independent but interconnected because gas in sufficient volume is required along the chain. A new trend for most oil and gas companies and other gas actors is however to become involved in each segment of the full gas chain to maximize their share over the entire *gas value chain.* This objective may lead to more *integrated gas projects* when the legislation so authorizes, or otherwise–in particular when the activities have to be *unbundled* along the full gas chain as in Europe or in North America–by participating with distinct vehicles to each segment activities under an integrated gas strategy.

3.3 Guidance on gas pricing: main differences with oil pricing

In any gas agreement great attention should be paid to the gas valuation clause. Indeed, gas marketing and price determination are generally more complex than for oil and petroleum products for many reasons as explained below.

3.3.1.1 Overview of gas marketing and pricing methods along the supply chain

Upstream processed gas sales may be made using two main categories of sales agreements each one having its own pricing system. Gas is often sold under negotiated long term contracts while short term and spot sales based on selected quoted gas prices are developing.

- ***Long-term sales agreements*** may last up to 25 years for LNG sales contracts. In developing countries, due to the high cost of new gas infrastructure, most of the gas is usually sold under long-term contracts providing *inter alia* for an annual volume commitment and a base gas price at a given date, as agreed during the negotiations of the contract. The base price is then periodically adjusted according to a specific revision formula containing a list of agreed indices such as the quoted prices for a set of crude oils (the so-called "oil indexation") and/or for gas competing fuels as well as indices representative of costs, inflation and sometimes currency exchange rates.

- ***Under short-term agreements or spot sales.*** Under such sales gas price may be either determined by reference to a selected quoted "spot" gas price (applying a negotiated differential) or a negotiated fixed gas price. This spot gas market which is largely used in North America is now developing in Europe. Recently, more LNG sales are even made on a spot basis. This may occur for example when the LNG long-term buyer is the marketing affiliate of an integrated company which may decide to resell on the spot market a portion of the long term gas volume for maximizing its overall revenues when authorized by the LNG seller. For the time being, the gas spot market although growing remains relative to oil sales quite small outside North America, due to the share of the long term gas sales contracts required for investing in costly infrastructure.

Gas may be valued at different points along the gas supply chain such as:

- *At* the *outlet of the gas field*, after its primary processing. This price is often called the ***field gate* (or ex-field) *price*** and is generally applied in the upstream sector for taxation.
- *At the gas export point in the producing country*, in case of pipeline export or LNG exports. It corresponds to the sale price at specific delivery points along a pipeline or to the FOB export price at the outlet of an LNG plant.
- *At the point of LNG delivery abroad in the gas importing country*, corresponding to the CIF or DES (delivered ex-ship) export price inclusive of LNG shipping costs.
- *At the consumer* or *end-user delivery point in the producing or importing country.* This consumer price, often called the ***city-gate gas price*** in case of wholesale or retail trade is fully inclusive of any transmission and distribution costs.

They are several possible methods or approaches for determining gas price, from negotiated prices representative of market prices to regulated prices as explained in Box 2. Often, a combination of market and regulated approaches applies over the gas value chain.

On American markets the upstream gas sales prices for transactions are determined locally based on **gas-to-gas market competition methods**, considering the gas supply/demand situation reflected by the spot gas price quotation at the relevant reference terminal, **adjusted on a net back basis** by introducing a differential equal to any processing, transmission and distribution pipeline tariffs. Regulated tariffs apply to such facilities which are regularly published following their determination on a "**cost-of-service basis**" as defined in Box 2.

In Continental Europe, which imports for its domestic supplies growing large quantities of gas from gas exporting countries, by pipelines or by LNG tankers, prices are determined as follows:

- under long-term purchase contracts–which supply the large majority of the consumption–by applying the pricing indexation formulae stipulated in such contracts;
- and under spot contracts by reference to a selected spot quotation.

Box 2: Methods for determining gas prices

Market-based methods correspond to situations where the prices are negotiated *at arms' length conditions* between third parties under full conditions of fair competition. Prices so determined are representative of the gas market at the level of a country or a region– what is called "*gas-to-gas*" *market competition*– and also of the other fuels prices competing with gas for the buyer's uses.

However, in the case of gas prices negotiated between affiliated entities or when the gas is not sold *at arms' length conditions*, the fiscal regime should contain specific gas transfer pricing rules applicable to such sales to prevent taxpayers from setting arbitrary gas sales prices for taxation purposes.

Cost-plus or cost-of-service methods apply to cases where the gas prices are fixed in such a way to provide the opportunity to recover all the eligible costs plus an adequate and reasonable return on investment–which may be an internal rate of return on investment (IRR or ROI) or on equity (ROE) incurred for the project.

The cost-of-service approach is often adopted within a country to prevent monopolistic positions in the negotiation between the seller and the buyer in case of *de facto* monopoly, for example for supplying gas or for access by a third party to existing gas pipelines or a storage facilities. The gas price so determined is by definition not directly related to the market and therefore it should be compared with the price of gas competing fuels in order to check that it does not exceed such competing market price.

The cost-plus or cost of service methods, when not defined in commercial contracts, are governed by regulations issued by the government and therefore are classified as "*regulated*" pricing. In this case, the gas price, or the tariff for a segment of the gas supply chain, is subject to an approval by the competent gas authority in the country. Different regulated gas prices may be fixed depending on the sector of gas use.

Discounted regulated price for specific uses may exist when, for socio-economic reasons, gas regulations authorize the competent authority to exceptionally fix gas price at more favourable terms and conditions for some categories of end-users, introducing a subsidy element to be compensated by other gas consumers.

Such a policy option should be carefully assessed as the subsidy may introduce wrong signals to the consumers and lead to a non-optimal allocation of the available gas resources. Gas exporting countries, especially the large oil exporters in the Middle East benefitting from considerable petroleum revenues, have introduced such a policy on their domestic markets initially limited to associated gas resources and now related to any type of produced gas in the country.

Hybrid methods combining both market-based methods and regulated methods apply for pricing formation, with the applicability of different methods along the segments of the gas supply chain from the producer to the end-user.

Net-back value pricing **methods** often apply in the gas industry, especially for determining the long-term sale price to end users in comparison with alternative fuels. They are market-based methods focusing on the determination of the **fair market value** of the gas in the long run at a given point along the gas value chain and for each specific use and consumer (or group of consumers) in relation with the costs for the consumer of competing fuels. This method allows the determination of the *maximum gas price* to remain competitive with alternative competing fuels solutions available to the customers. Then, the seller may propose in contract negotiations a gas price fixed slightly cheaper than the competing fuel prices, adjusted for any differences in investment, cost, efficiency, quality, taxation, including when relevant carbon emission, tax, etc.

This net back value pricing approach must be carried out when preparing any gas sales contract negotiations. Its implementation is however not easy for long-term contracts as its depends on the type of customers, their gas uses and the identification of the effective options available to the customers for selecting the workable alternative fuels solutions to gas, such as heating oil, diesel oil, low sulphur fuel oil, coal, etc.[7]

3.3.1.2 Gas price is governed by regional gas markets

They are several daily quoted gas prices in the world representatives of spot gas prices or future gas prices at the terminal or trading hub for which they are established and under the specific terms and conditions of each quotation. On the contrary, the long-term gas prices often remain confidential.

Three main regional gas markets exist today in the world when comparing the published gas quotations**: North America, Europe and Asia.** The variations in the spot prices between the three regional markets can be significant. Globally, the North American prices became recently significantly lower than the European and Asian gas prices as a result of the "gas shale revolution" amplified by the 2008 economic crisis. Thus, the average spot gas prices in 2010 were the following in each regional market:

- In the US, at the *Henry Hub (HH)* price in central Louisiana–which is the leading gas trading hub in North America publishing daily quotations commonly used as a base for gas price reference purposes–the average quoted price in 2010 was \$4.4/MMBtu, 5% higher than in 2009 but still considerably lower than in 2008 (\$8.9/MMBtu) for the reasons explained above.

- In Europe**,** at the *National Balancing Point (NBP)* in Great Britain[8]–a virtual trading location for sale, purchase and exchange of gas in the UK. The average quoted price when converted from pence/therm into \$/MMBtu was in 2010 equivalent to \$6.4/MMBtu, instead of \$5.0/MMBtu in 2009 and \$11.4/MMBtu in 2008.
- In Asia, with higher quoted prices, above \$8/MMBtu.

Gas is usually valued cheaper than its oil calorific equivalent, in particular today in North America, with a variable ratio between gas and oil prices depending at a given date on the respective gas and oil supply/demand markets in the region. Thus in the US, the HH quoted gas prices have now become significantly lower than the equivalent calorific value relative to crude oil, corresponding to only one-third of the equivalent oil value instead of around 70-80% in the past.

The current *spot gas prices* became lower than the long-term contract prices since mid-2009, but the gap is reducing to \$3/MMBtu in Europe by the end of 2010. This difference results from the actual price indexation formulae applied under long term contracts mostly based on "oil price indexation" with a time lag and therefore they do not integrate the current gas surplus in the world which resulted in a consequent drop in spot gas prices. This explains why many long-term gas purchasers decided to ask for renegotiation of their contractual gas pricing indexation clauses in order to introduce a "gas spot price indexation" component in the existing "oil price indexation" formulae.

[7] Net back value pricing methods are also applied for determining on a "net back value" basis a gas price *at a given point* along the supply chain when the market gas price at the end (or another point) of the supply chain is known. Costs for the segments subsequent in the chain are deducted from the end point price to determine the price at an intermediary point of the chain.

[8] In Europe, they are other gas trading hubs for which price quotations are published, in particular :

- *The Dutch Title Transfer Facility (TTF);*
- *The Austrian Central European Gas Hub;*
- *The Belgian Zeebrugge Hub*.

4 GUIDELINES FOR DESIGNING A COUNTRY GAS STRATEGY AND POLICY

4.1 Overview of gas strategy and policy drivers

On a calorific value's equivalence, gas price is generally lower than oil, due *inter alia* to the fuel inter-competition between gas and cheaper coal. In addition, gas processing and transportation costs are greater than for oil. As a consequence of that reality **the profitability of a gas project is often lower than for an oil project of similar size if the same tax provisions apply.**

Therefore, when an oil producing country holds potential gas resources or reserves it is fully justified for the government to adopt a gas policy focusing on two key objectives:

- **First, to encourage new investments in gas exploration and development by the private sector** by offering sufficiently attractive conditions for gas activities in order to discover, appraise and develop more gas resources and increase existing gas reserves.
- **Second, to promote gas domestic uses in order to find a local market for utilizing gas and as a direct consequence increase its valuable oil exports** by reducing domestic oil requirements. Indeed when both natural gas and oil produced in a country, by switching from consuming oil products to gas, the domestic demand for petroleum products–and indirectly for oil–will be reduced allowing more oil from the country to become available for exports. Moreover, the additional exploration devoted to gas will also lead on the long run to the discovery of more oil resources. The produced gas can also be beneficially re-injected in oil reservoirs for increasing the oil recovery factor and therefore the oil production, bearing in mind that such re-injected gas is not lost because it will remain producible in the future.

They are many examples of developing countries having decided with great success to implement such gas strategy to foster more gas activities in the country with a view both to finding more gas and by reducing the domestic requirements on petroleum products increasing oil exports and production. No doubt that this trend will amplify in the context of a world looking for lower carbon sources of energy and paying more attention to the cost of CO_2 emissions which are greater when using oil in lieu of gas.

Generally speaking, the strategy of focusing on the development of the gas domestic markets when economically justified by the opportunity of obtaining higher net back gas prices from local markets than from exports is optimal in terms of revenues and benefits for the country. As a result of the relatively high costs incurred in the entire gas export supply chain, either in long-distance pipelines or under an LNG scheme, the economic value and the opportunity costs for the gas produced and consumed locally is often higher than exporting it when dealing with highly populated countries where large domestic gas markets can be developed. The new gas policy of Indonesia and Egypt is fully illustrative of the priority to local markets along with exports for the balance of available gas.

By definition, the **economic value** of gas resources corresponds to the *opportunity cost* of selling it either on the local markets or on the export markets. The **opportunity cost** can be calculated **for each gas use** considering its own value chain. It corresponds to **the net back value at the field gate** for a given utilization, which is the maximum gas price that an independent purchaser would be prepared to pay at the field gate for obtaining the minimum return threshold it is willing for its gas utilization project. When comparing for example the opportunity costs for gas exports with the one for utilizing gas locally instead of petroleum products in the power generation sector, generally this second opportunity cost is significantly higher than for exported gas. The difference would justify a higher gas selling price at the field gate under the upstream gas agreement and therefore may result in the long run in higher fiscal gas revenues for the government. In addition, the local economy will benefit from an access to a source of energy less expensive than the alternative fuel solution. The determination of the economic value of gas, for each potential use, is part of a specific *country gas market study* which should be performed when deciding on a gas policy.

The ranking of gas's uses depends if the country is a *gas supply-limited country* or a *gas market-limited* country. In the first situation of limited reserves, priority should be given to the domestic uses of gas and the constitution of the so-called "*gas national reserves*" required for covering with sufficient security the long-term local gas requirements, authorizing exports of any additional available gas when such reserves are identified. Egypt is fully illustrative of this strategy. In Canada and the US, a similar approach was followed as any gas export requires a licence and is only delivered if it is demonstrated that sufficient gas resources already exist to adequately cover the gas long-term demand. On the opposite, Qatar is an example of a gas market-limited country holding considerable gas reserves where priority is given to gas exports after the supply of the limited country needs.

4.2 Guidance for designing upstream gas policy and strategy

In terms of gas, the government policy concerning upstream should have the following contents and objectives:

- **Any petroleum policy should contain specific provisions on gas.** This policy may also address unconventional gas when prospective resources of this type may exist in the country in a favourable socio-environmental context.
- **The petroleum policy should encourage exploration investments by the private sector** dedicated to discover and appraise gas discoveries in addition to searching for oil.
- **Reasonable fiscal incentives should encourage gas field development investments** when they are discovered and appraised by the private sector and should encourage associated-gas monetization projects.
- Any oil field development and production plan should take into account the following objectives**:**
    - **Reduce gas flaring of associated gas and venting** and encourage commercial projects for using associated gas to prevent flaring.
    - In the same way, examine the solutions to reduce CO_2 emissions in each segment of the oil and gas supply chain.
    - **In oil fields, re-inject gas in priority** when such re-injection is justified for maximizing oil recovery and thus increasing oil production. This re-injected gas is not lost and can be produced at a later stage.
- In the same way, any gas field development plan should **maximize the economic extraction and sales of condensate and other natural gas liquids (NGLs)** contained in produced gas because such NGL sales may significantly increased the economic value of gas and therefore facilitate the global profitability of gas projects.
- Select an appropriate **gas pricing policy** for encouraging sales on the domestic markets in such a way to justify new viable gas development and utilization projects.

- The country should promulgate, or amend without delay, its petroleum legislation, taxation, regulation and model upstream contracts in a clear and fully consistent way with the above principles and policy.
- The upstream policy by itself is not enough for promoting gas: it has to be complemented **by a downstream gas policy** consistent with the objectives assigned to the upstream policy (see Section 4.3).

Encouraging new gas investments requires designing an appropriate legal, regulatory contractual and fiscal framework with sufficient incentives relative to oil. To that end **the specificities of gas and its differences with oil** have to be adequately taken into account, such as:

- **The higher development, processing and transportation costs for gas**, requiring more favourable fiscal terms for gas, especially for small- to medium-size gas fields.
- **The range in the size of gas fields for investing from small to large fields**. In terms of policy, attention should be paid to designing appropriate incentives for each size category of gas fields. Thus, when large gas fields are initially discovered in a country, the fiscal regime and access to markets should be established to continue to encourage both the exploration and development of small, medium and large gas fields in order to fully assess the gas potential of the country. For example, in Netherlands, in spite of the initial discovery of the giant Groningen onshore gas field, the government decided to open exploration in other onshore and offshore areas, using the gas production from the giant field as a swing producer in order not to defer the exploration and exploitation of the smaller and more costly fields.
- **The differences between associated gas and non-associated gas** which require, in the legislation and in the upstream agreements, specific provisions dealing with each type of gas.
- **The differences between conventional and unconventional gas resources.** The exploitation of the later may lead to higher costs and raises specific environmental and social issues resulting from higher well density and use of hydraulic fracturing which have to be addressed at the right time.
- **The considerable longer period required for assessing the economic viability of a gas project** than for an oil project. Thus, additional time periods (generally called "retention periods") should be provided for under the petroleum law and the petroleum agreement to properly appraise a gas discovery, identify the potential markets for such gas and study the infrastructure required to process and transport the gas, and negotiate and sign the necessary gas sales contracts with the interested customers prior taking a final investment decision.
- **The joint development of separate gas fields**. Often the need to aggregate the production of several gas fields, sometimes from various producers, in order, first, to reach the minimum gas reserves and production thresholds for justifying the construction of the required processing and transportation infrastructure and, second, to produce enough gas over a long-time period to interest the potential gas users. To that end, the petroleum law and the petroleum agreements should contain a special provision on *joint development* by several agreement-holders*.* This concept is different from the customary "unitization provision" which only concerns the joint exploitation of fields crossing the borders of a permit. The *joint development* clause goes beyond unitization as the fields covered by such clause may be separate and spread over a relative large area covered by more than one permit.

The legal, regulatory, contractual and fiscal provisions governing the upstream issues related to gas and implementing the principles stated above are presented in Sections 5 and 6.

More and more countries have now published a formal gas policy or a petroleum policy including gas issues. Thus, the following Box 3 contains excerpts from the amended petroleum policy decided in 2009 by the government of Pakistan. The specific objectives for promoting gas activities and the priorities applicable in similar gas consuming countries are highlighted. Pakistan is an historic gas producer which was able to supply its local demand from many gas consumers at a relatively low gas price. Due to the considerable increase in local gas demand new resources have to be rapidly found and developed in the country in order to limit the need for future massive gas imports at a higher international market price.

Regarding guidelines on associated gas, the following Box 4 is an excerpt from a document entitled *Guidance on Upstream Flaring and Venting Policy and Regulation* of March 2009 published by the *Global Gas Flaring Reduction Partnership (GGFR)* emphasizing on the many aspects to be considered for a coherent policy dealing with the reduction of gas flaring in a country. The corresponding principles include a comprehensive package of actions regarding technical and operational rules prohibiting flaring and venting along with measures for promoting gas utilizations projects.

4.3 Overview of downstream gas policy and strategy

The key objective of any gas downstream policy is to encourage the most efficient and economic utilizations of the produced gas first by the country and then through exports for the balance when large reserves exist. Therefore a *prioritization* between the various possible commercial uses of the gas has to be assessed by the country in liaison with the other concerned stake-holders for defining the right strategy and establishing priorities between the various potential gas uses. This will also help for organizing the timely building the necessary processing, transmission and distribution infrastructure facilities in the country.

The other main objectives to be considered in any gas downstream policy include the following:

- The award of sufficient encouragement to the private sector for creating and developing each of the commercially viable domestic gas markets, small and large.
- The construction by the gas producers, or other public or private investors, of the required plants for maximizing the extraction of natural gas liquids from the gas stream, such as condensates, natural gasoline, LPG.
- The definition of a competitive framework for the construction in priority of gas-fired power plants by domestic electricity companies and new public or private investors, as the opportunity cost for the solution of gas used in power plants is generally the highest in developing countries among the possible uses of gas.
- Establishing adequate conditions for using gas in sectors of the economy other than power, such as the gas energy uses in the industrial, commercial and residential sectors and as feedstock for petrochemicals (such as methanol, ethane, fertilizers, etc.), considering the respective opportunity costs for each use.
- Progressively building when justified the transmission pipeline networks for transporting the gas from the fields zone to the consumers zones, which may be quite distant, as well as progressively when economically justified selected distribution networks within the country, bearing in mind the huge front costs to be invested for such projects.

Box 3: 2009 Pakistan gas policy (excerpts from the petroleum policy document)

"Pakistan's average daily production of crude oil and gas in 2007-08 was 70,205 barrels and 4,176 million cubic feet, respectively. Pakistan's current crude oil production meets only 18% of the total demand for domestic consumption. The balance requirement is imported involving large expenditures of foreign exchange.

Domestic gas production and supply presently fails to meet the demand of domestic users, the industrial sector and power generation.

Furthermore, gas supply may soon become insufficient due to increasing demand and depletion of present reserves. This, in turn, will force Pakistan to soon begin importing large volumes of gas at international prices to feed the domestic market.

The Government of Pakistan is committed to accelerate an exploration and development programme in order to reverse the decline in crude oil production, to increase the domestic gas production and supply and to reduce the burden of imported energy which otherwise will have adverse effect on the balance of payments & trade.

In the current global energy price environment, E&P Policy has to be dynamic to meet the new challenges faced in meeting energy needs of the country at least cost option and to minimize the adverse effects on the economy of high import bill of energy.

Policy Objectives

The principal objectives of this Policy are:

*1. **To accelerate E&P activities in Pakistan** with a view to achieve maximum self sufficiency in energy by increasing oil and gas production.*

*2. **To promote direct foreign investment in Pakistan** by increasing the competitiveness of its terms of investment in the upstream sector.*

*3. **To promote the involvement of Pakistani oil and gas companies** in the country's upstream investment opportunities.*

*4. **To train the Pakistani professionals in E& P sector to international standards** and create favourable conditions for their retaining within the country.*

*5. **To promote increased E&P activity in the onshore frontier areas by providing globally competitive incentives.***

*6. **To enable a more proactive management of resources** through establishment of a strengthened Directorate General of Petroleum Concessions (DGPC) and providing the necessary control and procedures to enhance the effective management of Pakistan's petroleum reserves.*

*7. To undertake exploitation of oil and gas resources in a **socially, economically and environmentally sustainable** and responsible manner."*

Note: The policy document contains a number of other provisions not included here, *inter alia* detailed provisions on a new and more favourable gas pricing policy designed to offer to producers for new discoveries a higher minimum gas price than the current gas prices applied to the local sales remaining however lesser than import prices.

Box 4: Excerpts from 2009 Guidance on Upstream Flaring Policy (Source: GGFR)

"It is the host government's responsibility to develop and implement policy enabling flare and vent reduction investments…Specifically, the host government is responsible for establishing this environment through legislation, regulation and market/economic measures.

Specific policy measures will depend on the each country's circumstances and are likely to include both upstream and downstream sectors. However, some generic lessons can be drawn from successes in associated gas utilization:

1) Oil & gas legislation, and oil & gas concessions/licenses, should be clear, comprehensive and unambiguous on the treatment of associated gas.

2) Fiscal terms should encourage associated gas utilization investments: Special fiscal treatment of associated gas investments may be needed to overcome the high up-front capital cost and (relatively) poor economics of associated gas utilization projects.

3) The gas market should encourage and enable associated gas utilization with:
a) The oil & gas companies given the right to monetize gas, generally including gas export;
b) Open and non-discriminatory access to infrastructure, including gas processing and transmission facilities, and to electricity grids (to sell electricity produced on-site from associated gas); and
c) Market-based energy pricing.

4) Flare and venting regulation should be clear, with effective monitoring and enforcement: The right market conditions and investment incentive schemes should be complemented by flare and vent regulation in order to challenge operators to consider every gas utilization option.

5*) Reduction in legacy flaring requires a comprehensive and methodical approach: A generally accepted approach to address legacy flares and vents is to (i) create an environment enabling gas utilization investments (ii) establish a realistic flare/vent-out deadline (iii) coordinate operators' investment programs, and (iv) closely monitor them to ensure that they are implemented on time. Developing these flare reduction programs should be a cooperative approach in consultation with key stakeholders, particularly the operators. Although stakeholder consultations will take time and effort, they typically add value by:*
a) Establishing a challenging, but realistic flare-out deadline;
b) Identifying key issues and risks in implementation of operators' associated gas utilization programs, which in turn allow these to be addressed in timely fashion;
c) Developing a fiscal framework consistent with the country's flare and vent reduction policy;
d) Transforming the potential of the policy into results on the ground through greater trust, ownership, and commitment by stakeholders.

6) New oil developments should include provision for associated gas utilization: In new oil developments, associated gas utilization should be an integral part…

7) An integrated plan should be developed for both associated and non-associated gas: Flaring and venting reduction and non-associated gas development should be integrated into a country gas master plan and/or energy sector strategy

8) Finally, a combination of the above measures is essential to achieve significant reduction in flaring and venting."

The regulatory and fiscal framework governing such downstream infrastructure should meet at least three objectives:

- grant sufficient incentives to the investor in order to reach a fair and reasonable return on the equity it intends to invest in the project;
- prevent the creation of monopoly situations in any segment of the gas supply chain, and protect the third parties' users of such facilities and the end-consumers of gas from monopolistic situations;
- and encourage reasonable tariffs and conditions of access for the use by third parties of the infrastructure facilities existing along the supply chain, and for the sale of gas to the end-consumers.

Such principles are generally provided in a *Gas Law* and its related regulations which indeed deal with all the aspects related to the downstream (and midstream) segments of the gas supply chain, as highlighted in Section 7 below.

5 GUIDELINES FOR UPSTREAM GAS LEGISLATION, TAXATION AND REGULATION

5.1 Overview of upstream oil and gas legislation and regulation

Exploration and production natural gas activities are generally governed ***under the same Oil and Gas Upstream (or Exploration and Production) Law and Regulations***–the so-called "**Oil and Gas Law**" body of law–and not under a separate Upstream Gas Law. The reason is that both oil and/or natural gas may be discovered from exploration activities and therefore the rights granted to the State and the explorers concern both products. Oil and gas consist respectively in the liquid and gaseous forms of *petroleum* or *hydrocarbons* generated in underground formations. Moreover, the search for and exploitation of oil and gas require techniques and methods relatively similar.

As highlighted in the preceding sections, the specificities of natural gas exploration, development, production, marketing and economics are dealt with **in special provisions within *the Oil and Gas Law* providing for specific gas clauses and incentives**. As stated in a policy research working paper of the World Bank entitled "Legislative Framework Used to Foster Petroleum Development" (W. Onorato, 1995):

> "…***gas is not…"another form of oil***", *to be treated as such, mutatis mutandi. Rather, enlightened modern petroleum legislations have specially-tailored gas development and commercialization provisions to encourage positive actions on gas discoveries*."

Indeed, one of the main objectives for specific gas clauses under the petroleum law intends to get more attractive terms for gas relative to oil to (1) compensate gas's higher costs and lower value as already mentioned and (2) foster new gas projects and uses. The contents of such specific gas clauses are presented in Section 5.3 below.

A description of the main provisions of any Oil and Gas Law can be found directly in *The EI Source Book.* More details are available in Chapters 2 & 3 of the handbook entitled *International Petroleum Exploration and Exploitation Agreements: Legal, Economic and Policy Aspects (2nd ed. 2009),* Claude Duval, Honoré Le Leuch, André Pertuzio and Jacqueline Lang Weaver, published by Barrows Company Inc. New York.

The ways an Oil and Gas Law may be drafted depend on each country and its legislative system, for example the common law or civil code type. The preceding reference states that:

> *"The petroleum code in any country generally consists of at least two categories of instruments:*
>
> a) **The *Petroleum Act* or *Law*** *covering exploration and production (E&P) and other related activities, such as pipeline transportation. In most cases, refining and marketing of petroleum products are excluded from such an act. Recently, petroleum acts have been complemented by a Natural Gas Act or Law addressing the peculiarities of natural gas and containing provisions for … transportation, commercialization and utilization.*
>
> *b)* ***The E&P Regulations*** *made under the Petroleum Act, which may include* ***model forms*** *for each of the various licenses or contracts provided for under the act.*
>
> *Depending on the country's petroleum history and legal system, the extent of the petroleum act and the corresponding regulations and guidelines may vary from only a few dozen pages (as in developing countries with recent oil and gas production) to thousands*

of pages (as in North America and Europe where specific issues related to oil and gas activities have been addressed over many years to eliminate gaps in the regulations and to better clarify the application of the laws and rules)."

In most oil and gas laws downstream activities related to gas are not covered. Generally a gas law is separately promulgated dealing *inter alia* with such downstream issues as highlighted in Section 7 below.

Among the few exceptions of petroleum laws governing altogether upstream and downstream activities, but under distinct chapters of the law and separate regulations, one may mention the new Indonesian *Law 22 of 2001 Concerning Oil and Gas* which provides in particular that: "*Oil and Gas business activities shall consist of: (1) Upstream business activities which comprise: exploration; exploitation; and (2) Downstream business activities which comprise: processing; transportation; storage; trading."*

5.2 Overview of upstream gas taxation and incentives

The *Petroleum Law* typically deals with specific tax provisions for upstream oil and gas activities, unless a separate *Petroleum Taxation Law* is promulgated or a special part related to oil and gas fiscal issues is inserted in the *General Tax Code* which is now the recommended approach for mitigating conflict of law.[9] Details on the fiscal provisions for upstream activities are highlighted in the *EI Source Book* and in Chapter 13 of the handbook referenced above in Section 5.1.

Generally speaking, upstream gas activities are often covered *mutatis mutandi* by the same fiscal provisions than oil operations in most countries, as the tax law deals with *petroleum.* However, tax laws more and more provide for some specific fiscal clauses on gas with the aim of **introducing more favourable terms for gas activities** as the profitability of gas projects is frequently lower relative to oil projects for two main reasons: first, gas operations are often more costly especially for gas processing and transportation infrastructure; and second, gas is sold at a lower equivalent caloric value than oil.

The nature of fiscal incentives for gas depends greatly on the type of upstream petroleum contracts used by the country. Thus, the following tools may apply:

- Under concession agreements, reduced royalty rates for gas.
- Under production sharing agreements (PSCs), where most of the fiscal differences between oil and gas are of a contractual nature through more favourable cost recovery schemes and production split terms applicable to the investor in the event of gas production.

However, natural gas liquids including condensate are in most cases considered as oil for fiscal purposes under the tax law and contracts.

[9] The possible interaction between the fiscal provisions applicable to upstream petroleum activities when part of the petroleum law and those provided under the *General Tax Code* or the applicable *Investment promotion Code* has to be carefully assessed in order to prevent uncertainties on the applicable fiscal regime and potential conflict of law.

5.3 Specific gas clauses in oil and gas legislation. Illustrative country cases

The following guidelines summarize the main gas provisions to be dealt with under petroleum legislation and regulation to govern the rights on gas, regulate gas activities and address any gas peculiarities in relation with oil:

- As for oil, gas property when in the ground is retained by the State which is sovereign on its natural resources. The same arrangements applicable to oil for State participation and authorizing exploration, production and transportation activities under the petroleum law should apply to gas, with some adjustments.
- In case of gas discoveries, the law should authorize longer appraisal periods, and production periods, than for oil discovery, with the right to authorize a specific "gas retention license" for assessing the viability of a gas discovery and finding gas buyers.
- The law should also provide for mandatory joint development and exploitation of gas discoveries between several licensees when such system renders viable gas projects otherwise non commercial.
- The law should prohibit gas flaring except in very specific circumstances.
- The law should state the priorities for gas uses, in particular between domestic and exports uses, for gas re-injection in oil reservoirs. The law may also introduce, when the respective gas resources potential and demand environment of a country so requires, the principle of constituting national gas reserves and set conditions for authorizing exports.
- The law should define the specific fiscal incentives for promoting gas activities and the principles for gas pricing.
- The law should define specific provisions for unconventional gas.
- In countries with large gas export projects, the law may provide for the establishment of an offshore sovereign fund (SWF) where part of the government gas fiscal revenues is allocated for savings instead of immediately injecting all the gas revenues in the country budget.

Appendix 8.6 displays the following illustrative examples of gas clauses embedded in petroleum law:

- **Angola**, where the existing petroleum law apply to both oil and gas, to the exception of two articles providing for (1) a time period for submission of a development plan is lightly longer for a gas discovery than for an oil field, and (2) for specific clauses regarding associated gas, flaring–which is "expressly forbidden, except flaring for short periods of time when required for purpose of testing or other operating reasons"–and possible unitization and joint development which may "apply, duly adapted, to the exploitation of natural gas."
- **Vietnam**, where the petroleum law was amended in 2000 to introduce more favourable provisions for gas relative to oil, in terms of extended exploration–including a retention period of up to 7 years–and exploitation duration, royalty reduction along with the right to negotiate specific gas development and exploitation agreements.
- **Indonesia**, where the new Oil and Gas of 2001 covers both upstream and downstream activities–which is not the case in most petroleum laws–and highlights

the new priority to be given to domestic gas uses versus gas exports along with the introduction for gas of a new “domestic market supply” obligation.

- **Australia**, which was one of the first country to introduce the concept of a ***retention lease*** for allowing the exploration permit-holder of an oil or gas discovery to benefit in specific cases of a longer exploration and appraisal phase for discoveries. In addition, the possibility of ***joint gas development projects*** combining the resources and infrastructure with third parties is encouraged “**to jointly develop or complete an access agreement** for use of facilities or technology which provides an acceptable rate of return.”

5.4 Overview of Legislation, Regulation and Contracts applied to Unconventional Gas. New trends

Generally speaking, unconventional gas activities (such as tight gas, shale gas and CBM activities) are for the time being often governed by the natural gas provisions contained in the applicable Oil and Gas Law and Regulations, including for fiscal matters, and using as a basis the applicable model upstream petroleum contracts. However, more and more countries are introducing specific provisions dealing with each category of unconventional gas relative to conventional gas.

The reasons for such general approach are because unconventional gas (1) holds a similar composition to natural gas and may contain natural gas liquids (considered as oil for tax purposes), and (2) requires for its exploration and exploitation techniques derived from those customary used in the conventional petroleum industry with some minor adaptations. Another characteristics of unconventional gas is that their exploitation is often more costly that conventional gas because the formations where unconventional gas is extracted hold lower porosity and considerable lesser permeability. This obliges today to use hydraulic fracturing for allowing the gas to circulate from the formations, operations which are expensive and may impact the environment if the adequate protective measures are not followed.

Today, over 20 countries have granted exclusive exploration and exploitation rights to the private sector concerning unconventional gas activities, first in North America, Europe and Australia, and now in more and more developing countries.

With the growing development of unconventional gas activities, special legal, fiscal and regulatory framework within the Oil and Gas Law and Regulations should be supplemented for taking into account the specificities of unconventional gas, in particular regarding:

- *Operational regulations* governing exploration, appraisal, pilots, development plans and production. Thus, the development of unconventional gas requires a higher density of wells and therefore more land activities occur than with conventional gas activities, so leading to more land access authorizations and operations permitting than for conventional gas.
- *Environmental and social regulations* in order to mitigate the potential impact and perceived possible risks on the surface land, air quality and for underground water resources. Such impact may result from the local noise generated by the activities and the use of water mixed with extremely low concentration of chemicals for

performing the hydraulic fracturing work on each unconventional gas production well.[10]

- In certain cases, *fiscal incentives*, when the cost of unconventional gas is substantially higher than for conventional gas. A few countries have for example introduced a reduced royalty rate or a tax credit for tight gas production. Under PSCs, more favourable schemes for cost recovery and profit gas split may apply to the investor.
- *Licensing systems for awarding unconventional gas licences or contracts* under competitive bidding or direct negotiation processes. When conventional petroleum or coal exploration and production rights are already awarded over a given zone, regulations may provide for the grant of separate unconventional gas licences. Such regulations may give priority right for obtaining an unconventional licence to the existing holders of E&P rights, as in Indonesia.[11]

[10] Some countries have reservations on the use of hydraulic fracturing as this process is currently used. The industry is looking to improve it in order to limit the potential risk of fracturing on water supplies.

[11] As an illustrative example, Indonesia clarified that the Oil and Gas Law applies to CBM activities and also decided that for authorizing the private sector to carry out CBM projects in the country the PSC scheme initially retained by the country for petroleum operations is also applicable to CBM.
In addition, Indonesia issued in 2006 and 2008 regulations dealing specifically with CBM operations and organized bidding rounds for CBM. A*d hoc* provisions and specific terms more favourable to CBM investors were introduced under the PSCs. Last, a priority system was defined for awarding CBM PSCs when the concerned area is already covered by an Oil and Gas PSC or a Coal Mining licence: the first priority is granted to the existing PSC-holder.
Under the regulatory framework, the Indonesian CBM PSC holds a term of 30 years including an initial exploration period of 6 years–consisting of several sub periods–which may be extended by 4 years for assessing the viability of a commercial CBM project. The produced gas is supplied in priority to the domestic market and to the existing LNG plants already built in Indonesia to complement the feed gas they require.

6 GUIDELINES FOR UPSTREAM GAS CONTRACTS

6.1 Overview of upstream gas contracts

6.1.1 The rationale for using, as a base, standard E&P petroleum contracts

As highlighted under Section 5, standard exploration and production *petroleum agreements* entered into between the host country and qualified investors are applicable to both **oil and gas** upstream activities, and therefore deals with gas operations. The scope of such upstream agreements covers both the search for the existence of petroleum resources, *i.e.* oil and/or gas in a given area on an exclusive basis and, in case of commercial discoveries, the development and production of the corresponding oil and/or gas fields, as generally both opportunities may exist in the granted area. The contractual scheme for such agreements may be *concessions, production sharing agreements or service agreements*. Details regarding upstream petroleum agreements are displayed in the *EI Source Book*.

As "gas is not oil", any of the upstream agreements must include specific gas clauses dealing with the peculiarities of gas projects, such as the long lead time that may be required for identifying viable gas markets in case of gas discoveries and signing the related long term sales contracts with the interested gas buyers. Moreover, gas projects often require higher investment for field development, processing and transportation while the gas selling price to the buyers is comparatively lower than its calorific equivalent price relative to oil. This explains why the fiscal terms applying to gas production should be more attractive to the investors to reach their desired minimum profitability threshold.

This section will only analyze good practice concerning the wording of such gas clauses. Historically, Egypt was the first country to introduce in the 1980s with great success detailed gas provisions in its upstream petroleum law and contracts which are known as the "the Egyptian Gas Clause". Such clause was periodically revised for new contracts in order to take into account the evolution of the gas industry and continue to foster the development of gas activities in Egypt.

6.1.2 The scope of specific gas clauses required in E&P petroleum contracts

The specific clauses of any standard petroleum upstream agreement dealing with gas are basically the following:

- ***The definitions under the agreement***. They include definitions for *petroleum*, meaning oil and gas, *associated gas* and *non-associated gas*, *condensate*, *natural gas liquids*. The definitions of *petroleum operations* and *point of delivery* are also of importance as they define the scope of the agreement regarding upstream activities, comprising exploration, appraisal, field development and production, gas processing and gathering lines–when mainly related to the fields developed under the upstream agreement–but excluding transportation pipelines and downstream facilities not primarily dedicated to the agreement's fields. Thus, an LNG plant is generally outside the scope of an upstream agreement except in very specific cases when the plant is only dedicated to a field or group of fields.

- ***The appraisal program for assessing the commerciality of a non-associated gas discovery up to the decision to exploit it***. Marketing of oil and gas are quite differentiated. For oil, there is no need to enter into long term contracts for future oil commercialization of oil. On the contrary, in the majority of developing countries the signing of long term contracts is often a pre-requisite for declaring the commerciality of a gas field.

In addition to the appraisal of the discovery and the preparation of the field development plan, the markets for the discovered gas have to be identified and the corresponding long term gas sales contracts with the buyers signed prior to the submission for its approval of a gas field development plan to the State. Then, the investor will take its final investment decision for the project.

Thus, more time relative to oil development projects is necessary for assessing the commercial viability of a potentially commercial gas discovery. This extra time is often granted under the specific *gas retention period* mechanism stipulated in the agreement, when authorized under the law, which allows extending for gas the duration of the exploration and appraisal periods.

- ***The joint development of gas discoveries held by various producers.*** To implement such an objective, each upstream agreement in the region should contain a provision dealing with an obligation when economically justified to jointly develop and produce gas resources identified in the region by different companies active under separate upstream agreements when the utilization of a joint scheme renders commercial the exploitation of a group of gas discoveries by sharing the processing and transportation infrastructure otherwise non commercial. This joint obligation is similar to a kind of unitization scheme for the exploitation and transportation within the unitized area.

- ***The utilization of associated gas.*** The agreement should specify the order of priority between the possible gas uses, from its utilization in the petroleum operations to commercial uses. The highest priority consists in the gas being re-injected in the oil reservoir for maximizing oil recovery and eliminating gas flaring.

  When the company is not fully using the associated gas, the agreement grants the right to the government to purchase such gas. The purchase price is either at cost– indeed at the *incremental cost* incurred for the facilities specially-built at the request of the government to permit the government to take delivery of the gas at a given point, without any compensation for the other costs related to gas discovery and extraction or more frequently at a higher negotiated price recognizing the value of gas.

- ***The priorities between the domestic uses of gas and exports.*** To that end, the agreement may include (1) a ***domestic gas obligation*** to supply part of the local gas market, in proportion to the share of production held by the agreement-holder relative to the country's total gas production, and (2) the procedure for ***authorizing gas exports.***

  Sometimes, the concept of constituting a minimum threshold of ***national gas reserves*** in the country may be introduced in the regulation and detailed in any upstream agreement, with the aim of giving priority to domestic gas markets versus exports until the reserves threshold is reached. Similarly, gas exports projects are often subject to their prior approval by the government during the procedure for adopting field development plans.

- ***Rules for gas marketing***. When the government holds a right to take a share of the produced gas in kind, as under PSCs, the agreement provides for ***joint marketing and sale*** *of gas to potential buyers* in order to facilitate the conclusion of gas purchase contracts by aggregating the entire field production.

- ***Gas pricing****.* Because gas is marketed and sold under principles different from oil, and gas prices depend on its uses and differ between different regional markets, an appropriate gas valuation clause must be carefully inserted in the agreement to complement the oil price valuation provisions and ensuring that gas is sold at a fair market value. The clause deals respectively with the price for sales to third parties at arms' length and the other categories of sales to the domestic users and for exports. Often the gas sales contracts must be approved by the government.

- ***Fiscal clauses adjusted to gas economics***. The fiscal adjustments for gas versus oil production may concern lower royalty rates and more favourable conditions for the investor regarding cost recovery ceiling and profit gas sharing. Thus, under Indonesian PSCs, while the contractor often gets a share from 25% to 35% in the *profit oil split*–on a post-tax basis–depending on the vintage of the contracts, its share may reach 30% to 40% for gas.

  Such adjustments of the fiscal and contractual terms applicable to gas production are less required when under the agreement the petroleum rent sharing between the State and the investor at a given date is based on a fiscal device related to the effective profitability reached by the petroleum project.

  Two contractual approaches for defining gas fiscal terms should be disregarded. First, the approach selected in certain agreements of not stipulating, at the date of its signing, the detailed fiscal terms applicable to future gas discoveries, considering that such terms will be negotiated and agreed at a later stage when a potentially viable gas discovery is made, is not recommended as it creates for the investor a disincentive to search for gas and appraise a gas discovery.

  Second, the approach of fixing identical terms for gas than for oil under an agreement is also not recommended as it does not recognize the generally lower expected gas price relative to oil. This is the situation for example when the agreement states that in the event of gas production the fiscal terms applied to oil for royalty or profit split are directly applicable to gas by only converting from oil to gas on a pure calorific equivalence basis–that is using a conversion factor of around 6 Mcf per barrel oil equivalent–the increments of production of a given sliding scale based on oil production. Such a conversion should be made considering at a minimum the respective effective prices of gas and oil.

  Concerning *natural gas liquids*, the agreement often states that they are treated as crude oil for legal and fiscal issues which is generally appropriate from an economic point of view.

- ***Accounting rules.*** Their purpose primarily aims how to allocate, under the agreement and for all fiscal purposes, the respective "gas costs" incurred for gas operations and "oil costs" directly related to pure oil operations, for example for cost recovery under a PSC.

- ***Possible use of a development gas contract***. This generic gas upstream contract category detailed in Section 6.2 deals with the development of gas fields already discovered by another company which previously relinquished the field area.

- ***The treatment of transportation pipelines, processing and LNG plants.*** Often, the contract states that such projects are covered under distinct contractual and fiscal arrangements and considered as *segmented projects* versus a fully integrated project, as explained in Section 6.3. In particular, a special fiscal regime may apply to an LNG plant as described in Section 6.4.

6.1.3 illustrative country cases on upstream gas contracts

For illustration purposes of the above guidelines, **Appendix 8.7** reviews the specific gas clauses used in the following countries:

- **Vietnam**, which is the example of a country holding substantial potential gas resources which decided to promote the exploration and monetization of such resources in domestic projects. This policy is reflected under the terms of the 2007 model production sharing contract (PSC) which contains many clauses regarding gas such as the obligation to appraise and develop a commercial gas discovery, the right to obtain a “gas retention period” to assess the commerciality, the priority between the uses of the gas, and fiscal incentives.
- **Timor Leste**, which is a new gas LNG exporter willing to increase its gas reserves through new discoveries. The 2006 model PSC contains modern gas clauses designed to foster investments, in particular with the grant in case of a non-associated gas discovery of a 5-year retention period for evaluating the commerciality of the discovery–either alone or jointly with other discoveries in the region–the procedure for approval of gas contracts, the no-flaring obligation and the methods for gas valuation. The fiscal regime applicable to the contractor and the production sharing terms remain identical both for oil and gas as a result of the introduction of a supplementary profits tax assessed on an effective profitability criterion.
- **Angola,** which is an OPEC oil exporter where associated gas was usually flared. No priority was given to gas activities until a new policy decision was recently decided for limiting flaring, using gas locally and building an LNG plant for gas exports. The PSC reflects the former strategy as it grants to the contractor rights to oil and only to the portion of the associated gas required for its own operations, the balance of produced gas being available to the national oil company (NOC) at cost. In case of a non-associated gas discovery, the rights for its appraisal and exploitation are automatically vested in the Angolan NOC without any compensation to the contractor, except if the NOC invites the contractor to participate in the development of the gas field on terms to be agreed upon. Such principle providing the automatic transfer of a gas discovery to the State or its NOC was customary in many countries several decades ago prior to the introduction by Egypt in the 1980s of its so-called *gas clause.* Now, such transfer to the State remains quite exceptional as the majority of developing countries desire on the contrary to foster investments in gas exploration and development projects by granting to the PSC-holder the same exploitation rights whatever the nature of the discovery, oil or gas, and often offering more attractive fiscal and contractual terms for gas projects.
- **India,** with an illustrative example of a model PSC dealing with CBM exploration and exploitation.

6.2 The applicability of development gas contracts when gas was already discovered

In certain countries gas discoveries were made previously by companies at a time their development was not considered economically viable by the discoverer for many reasons, explaining why the corresponding acreage was surrendered to the State. Today, as gas becomes considerably more attractive, new companies or the State may desire to develop the already discovered gas resources without having the burden of bearing past exploration risks and costs–the so-called “sunk costs”.

When the main object of a new agreement is to develop existing gas discoveries without further exploration, a specific ***gas development agreement*** **(GDA)** may be executed. It may include an appraisal obligation for certifying the existing gas resources within the granted block prior to making a final investment decision. Thus, instead of using an exploration and production sharing agreement (EPSA), the solution of a pure **development and production sharing agreement (DPSA)**, or an **appraisal/development and production sharing agreement (ADPSA)** may be selected. The rights and obligations given under such DPSAs vary depending on the concerned projects but generally include a field development obligation while excluding exploration rights. To the exception of some integrated projects as indicated in the next Section 6.3, DPSAs do not generally apply to the gas downstream activities which are in most cases subject to different legal and fiscal regimes.

As an example, this approach was followed in Qatar for the progressive development in geographical sectors of the giant non-associated gas North Field, the largest world's gas field discovered in 1971 which covered 6,000 sq km and contains around 15% of the world's gas reserves.[12]

6.3 Differences between integrated gas contracts and segmented gas projects

Another type of gas agreements is classified as "***integrated*** *gas development, production and commercialization agreements*" where the scope of the agreement addresses several segments of the gas supply chain, both upstream activities and some downstream activities under an integrated project. To be considered as an *integrated gas project*, the project must be owned and operated by the same group of companies holding in each of the segments of the project the same participating interests, a condition for an effective integration from a *legal, operational, economic and fiscal* point of view. This may concern the development of a gas field along with the construction of a gas-fired power plant, an LNG plant, or a GTL plant, in an integrated way without splitting the supply chain into separate ***segmented*** projects and agreements, where each one is covered by specific legal, operational and fiscal regimes and company ownerships. In most cases, integrated projects apply to projects where the exploration risks on the concerned gas resources no more exist or remain relatively limited.

For the time being, they are very few examples of so defined integrated contracts in the world along the gas supply chain.[13] Moreover, more and more laws provide for the

---

[12] In Qatar several DPSAs were concluded for the development of sectors of the North Field. In addition to granting the right to develop, produce and sell the natural gas liquids extracted from gas, DPSAs often provides for the sale to the government or third parties of the processed and treated gas at a defined delivery point for domestic uses or exports.
Two major domestic projects are performed in Qatar under DPSAs arrangements. First, the 25-year *Al-Khaleej Gas (AKJ) Project* signed with ExxonMobil in 2000 with a production capacity of 1.75 Bcfd plus condensates, a part of the gas being sold to a GTL plant. Second, the *Barzan Gas Project* entered into with the same company in 2007 aiming a 1.5 Bcfd gas production long with 100,000 bpd of condensates. A third project signed in 2001 with another group of companies, the *Dolphin Gas project*, concern the development and sale of gas to third party buyers for its export by pipelines to UAE.

[13] For illustration purposes, two examples of integrated gas projects concerning very large gas projects may be mentioned below. The first example corresponds to the integrated gas agreement entered into in 2004 between Sonatrach, Repsol and Gas Natural mainly for the exploitation of gas discoveries in the region of Gassi Touil which are governed under a production-sharing system as well as the construction of an LNG plant and commercialization of LNG. The contract was revoked later apparently in relation with its delayed implementation. The second illustrative example is the integrated DPSA signed in 2004 between the government of Qatar and Shell providing both for (1) the

unbundling of the gas supply chain segments, the contrary of integration, in order to encourage competition on each segment of activity and prevent monopolistic positions.

When the gas activities are consolidated under the same fiscal regime at the level of the country, without any ring fencing per project or per upstream agreement or per licence, the project may be assimilated to an integrated one, such as in Norway for the Snovhit LNG plant holding a capacity of 5.75 Bcm per year built for the exploitation of the Snovhit offshore gas field, the first LNG plant in Europe.

6.4 Legal, fiscal and contractual framework applicable to LNG plants

Several legal, fiscal and contractual frameworks apply to the 30 LNG plants in operation in the world which may be classified into three main categories.

The segmented approach under which the LNG plant is considered as a distinct project along the gas supply chain, outside the scope of the upstream activities and therefore not covered by the producer's upstream gas agreement. As a consequence, **the LNG plant is in this case considered as an industrial project** governed under an agreement or licence with the State distinct from the upstream agreement, and therefore subject to a different regulatory and fiscal system than the upstream project. It often provides for a lower government take in the profits generated by the LNG plant. The feed gas for the LNG plant is purchased to the upstream gas producers by the LNG plant owners at a negotiated price and the produced LNG is directly sold by such plant owners to third parties or affiliates. Examples are LNG plants in Equatorial Guinea, Yemen or Malaysia.

An alternative to the segmented approach is **the tolling scheme** under which the gas producers signed a *tolling contract* with the separate LNG plant company and then sell to third parties or affiliates the LNG generated by the plant. The LNG plant company may have share-holders different from those participating in the upstream activities, or with different percentages of participation than in upstream activities. The LNG plant is operated as an industrial project subject to a fiscal regime different from the upstream one. Such a scheme is fully appropriate to *common user LNG facility*, such as the Browse plant in Australia, the LNG plants in Egypt or Trinidad and Tobago, which may be used by third parties paying a *toll tariff* for processing gas.

The integrated approach combining within a same unit the upstream activities and LNG plant operations. This scheme requires that the same entities hold identical participating

---

offshore development and production of 1.6 Bcfd from an areal sector of the giant gas North Field, (2) the construction and operations of a large GTL plant (3) and the sale of the 140,000 bpd GTL resulting from the conversion, 120,000 bpd of natural gas liquids plus the ethane obtained during the processing of the produced gas. The total investment for this unique project amounts to around $18billion, one of the largest projects in the petroleum industry. Its potential interest lays at the end in the direct sale of GTL products of high quality, such as diesel oil or kerosene, instead of the sale of gas or LNG, without the constraint of entering into long term gas contracts as for LNG. By integrating the GTL plant under the upstream production sharing agreement, including the sale of the GTL products, the government directly benefits *at any time* from the evolution of the GTL products prices in proportion to its share in the profit petroleum split under the DPSA which is based on increments of production and a factor "R", a multiple of the net cash flows/investment ratio.
On the contrary, for another GTL plant built in Qatar the contractual arrangements correspond to a segmented gas supply chain scheme: thus, the plant owner purchases the feed gas to the distinct AKG DPSA-holder under a negotiated gas sales contract.

interests in the upstream and LNG activities and does not encourage the utilization of the LNG plant by third parties. Therefore, such a scheme mainly exists in large gas exporting countries such as Qatar for some of its LNG plants and one GTL plant.

The fiscal implications of the selected contractual approach are significant. The integrated approach holds the advantage of eliminating the obligation of fixing a gas transfer price at the field gate for the feed gas supplied to the LNG plant, with the constraint of maintaining the same participating interests over the two components of the project and therefore limiting the possible access by other producers to the LNG plant when on stream.

In segmented projects, attention should also be given to the gas transfer price in case of affiliated companies participating in the two projects.[14]

6.5 Other types of upstream gas agreements

While the upstream gas agreements is entered into between the State and companies willing to invest in gas exploration and production, there are other types of contracts concerning the exploitation of gas, in particular:

- The agreements dealing with the sale of the gas to buyers called ***Gas sales and purchase agreements*** signed between the gas producers and the buyers of the gas. They provide for the long-term sale by the seller to a buyer of certain annual quantities of natural gas, delivered at a given point of the gas supply chain for an agreed price generally subject to an *ad hoc* indexation formula. Such contracts often last between 15 to 25 years and contains an obligation of "**take or pay**" for the buyer.
- ***Gas balancing agreements*** for allocating under lifted gas between the producers of a gas field when joint selling is not possible.
- ***Gas transportation agreements*** dealing with pipelines. They provide for the annual contractual quantities to be transported, the capacity reservation and the determination of the tariffs along with a "**ship or pay**" obligation for the shippers.

Details on each of the above type of contracts are summarized in **Appendix 8.8**.

[14] For simplification purposes, Australia has established specific *Gas Transfer Pricing Rules* for LNG projects to prevent taxpayers from setting arbitrary upstream gas sales price where both the upstream interests and the downstream interest (as LNG activities) are held by affiliated entities of a group, as for the Ichtys LNG project. The Gas Transfer Price in such case is the average of the "Upstream Cost plus Price" and the "Net Back Price" (based on LNG FOB Sale Price less Downstream Costs including the plant). Such a method holds the consequence of automatically allocating the *petroleum rent* to the two projects, upstream and downstream, instead of allocating it primarily to the upstream sector, **a policy that countries are not always prepared to accept** as the risks for the investor differ significantly between upstream and LNG activities.

7 OVERVIEW ON DOWNSTREAM GAS LEGISLATION, REGULATION AND TAXATION

7.1 Introduction on downstream legislation, regulation and taxation

The downstream gas sector along the supply chain consists mainly of the activities related to the downstream transmission pipeline networks, the distribution networks and facilities up to the gas end-users and the gas supply to the consumers including gas imports and exports. Stand-alone processing stations as well as LNG and GTL plants are generally considered as part of the downstream sector although there are exceptions in some cases, for example under an integrated project scheme (see Section 6.4) or when they are primarily related to upstream gas field operations.

The scope assigned to this Guidance Note, for the time being, focuses on upstream gas issues gas. However, it appears useful for the reader to summarize the main legal and regulatory aspects dealing with downstream gas activities because they correspond to an essential segment of the supply chain for the monetization of gas resources.

Downstream gas activities are generally governed under a **Gas Law** and its regulations, a special legal category dealing only with downstream gas activities in most cases. Gas Laws were firstly promulgated in the largest gas consuming countries for protecting the consumers from monopolistic situations and allowing them to benefit from relatively low gas price in order to develop the country gas demand while ensuring a sufficiently attractive framework to the investors for encouraging the necessary investments to build the gas infrastructure within the country under a growing gas demand.

The fiscal regime applied to downstream activities often consists of the **general tax code** of the country, at the difference of the upstream sector where a specific tax regime is defined for dealing with the specificities of petroleum rent sharing.

7.2 Overview of gas laws and regulatory frameworks

Today, many developed and developing countries have enacted a **Gas Law** dealing with downstream activities as part of their policy for encouraging the development of domestic gas demand and facilitating when appropriate gas exports.[15] As already mentioned in Indonesia a single law, the *2001 Oil and Gas Law*, covered both upstream and downstream activities, but each activity is dealt with in distinct chapters of the law and in separate regulations. This approach of integrating the downstream issues within the Oil and Gas Law remains rare in the world.

The scope of Gas Laws depends on the gas context and the policy decided by each country, *inter alia* on the willingness or not of the country to foster the development of gas markets and the priority given to the domestic supply versus the exports. **However, similarities are often found between the existing Gas Laws, many concepts being indeed derived from the latest US and UK Gas Laws**, including: the role of a gas regulator, the regulatory framework for construction and use of transmission pipelines, storage facilities, distribution networks, supply and marketing activities, imports and exports of gas, gas pricing, etc.

[15] Among the developing countries, one can mention the following illustrative examples of dedicated Gas Laws: in Africa *The Gas Code of 30 December 2002* of Cameroon; in Central Asia *The Law on Electricity and Natural Gas of 21 May of 1999* as amended of Georgia; in Latin America the *Law N°11.909 of 4 March 2009 on Gas* of Brazil supplemented by its decree of application of 2010.

In developing countries, the gas regulator is often the petroleum agency itself responsible both for upstream and downstream activities, as in Brazil where this role is managed by the petroleum agency, ANP, pursuant to the 2009 gas law. For the promotion of new gas projects, facilitating third party access to existing gas infrastructure and introducing transparency over domestic gas markets, ANP created a dedicated public web gas portal.

7.3 Illustrative country cases on gas laws

Appendix 8.9 highlights four representative country cases which gas laws in effect:

- **The US**, the largest gas producer and consumer country in the world. The first gas law promulgated in the US was *the Natural Gas Act* (NGA) *of 1938.* This act was periodically amended or supplemented, in particular by *the Natural Gas Policy Act* (NGPA) *of 1978*, *the Natural Gas Wellhead Decontrol Act* (NGWDA) *of 1989*, and the many orders issued by *the Federal Energy Regulatory Commission* (FERC), the competent federal authority for the sector. The US gas regulatory framework went through different phases and continues to evolve. While the gas price was controlled up to 1978, this is no more the case as there is a move towards more deregulation. However, regulated pipeline tariffs and third-party open access on a non-discriminatory basis for onshore and offshore gas pipelines continue to apply to foster the development of gas markets and marketing of gas by third parties.
- **Canada,** a large gas producer, consumer and exporter. The principles under the gas acts are similar with the US pricing and downstream gas framework. As in the US, gas exports or imports are subject to obtaining a prior *gas export or import licence* following an open hearing process.
- **The UK,** a large gas producer and importer. The country enacted several gas laws dealing with downstream issues, namely: *the Gas Acts of 1948, 1965, 1972, 1986 and 1995*, such laws being supplemented *inter alia* by *the Energy Act of 2008* and the UK and European Union competition legislations. This succession of gas laws illustrates the evolution of the UK downstream gas policies from the 1948 gas nationalization towards the 1986 and 1995 gas activities' privatization designed to create a more open and competitive sector while protecting the interests of customers. *The Office of The Gas and Electricity* Markets (*Ofgem*) is the regulator for the UK's gas and electricity industries. Its role is to protect the consumers and promote competition in the supply of gas. In addition, the *Petroleum Act of 1998* dealing with upstream gas activities contains provisions aimed to encourage third-party access rights to offshore downstream gas pipelines.
- **Cameroon,** a small oil exporter with some gas resources not yet fully utilised. The first Gas Code was promulgated recently in 2002. Its scope is illustrative of the objectives and content of a gas law in a developing country designed to foster the development of the domestic gas industry. The downstream gas sector is regulated by the minister responsible for petroleum with the possibility in the future to establish an agency. The gas transmission and distribution activities are subject to the grant of concessions awarded for a renewable period of 25 years on the conditions stated in a *concession contract* defining the rights and obligations of the transporter or distributor. The principles for pricing of services and gas provide for a "*cost of services plus a reasonable return on equity*" approach, as often the case in many countries. Therefore, the companies engaged in several downstream activities are obliged "to keep separate accounts for each transportation and/or distribution concession.

8 APPENDICES

8.1 Appendix 1 – Main units and conversions in the gas industry

M (or k)	Thousand or kilo (10^3); although sometimes M means Million in certain publications
MM	Million or mega (10^6)
B (or G)	One thousand million, or billion, or giga (10^9)
T	Tera or trillion (10^{12})
Q	One quad (10^{15})

Length or area

1 meter	= 3.28 feet
1 square kilometer	= 247 acres

Volume

1 barrel (bbl)	= 159 liters = 42 U.S. gallons = 35 UK Imperial gallons
1 m^3 (cubic meter)	= 6.2898 barrels
	= 35.31 cubic feet
1 Tcf (Tera cubic feet)	= 28.32 Gm^3

1 Mcf (Thousand cubic feet) = 28.32 m^3
1 MMcfd (Million cubic feet per day) = 10.34 Bcm/year

Energy or Heat units

1 MM BTU	= 1.056 GJ (Gigajoules)
1 therm	= 100 000 BTU = 25,200 kilocalories
1 GJ (giga joules)	= 0.95 MM BTU
1 kWh (1 kilowatt-hour)	= 860 kcal = 3,600 kJ = 3,412 Btu
1 MWh	= 3.412 MMBtu
1 kcal (kilocalorie)	= 3.968 BTU = 4,187 kJ (kilojoules)
1 BTU	= 0.252 kcal = 1.056 kJ
1 thermie	= one thousand kilocalories

Gas prices

Depending on the country, they are often expressed in the US in $/MMBtu, in the UK in pence/therm, and in Continental Europe in €/Gjoules or in €/MWh.

Approximations or rules of thumb for energy conversions

- 1 BOE or boe (Barrel of oil equivalent, including crude oil NGLs) is approximately equivalent to 5.8 to 6 Mcf of natural gas or 6 to 6.6 MM BTU, depending on countries. The conversion factor depends indeed *on the respective energy content* or gross heating value of the gas and oil.
- 1 TOE or toe (tonne oil equivalent) ≅ 10 MM kcal ≅ 42 GJ ≅ 40 MM BTU
  ≅ 7.3 BOE
  ≅ 1,100 m^3 of natural gas
  ≅ 0.8 m^3 of LNG
  ≅ 12 MM Whr
- 1 MM tonne per year of oil ≅ 20,000 bpd

For example, the average Btu content for each energy source consumed in the US is approximately the following:

- 1 cubic foot of natural gas = 1,027 Btu (based on U.S. consumption in 2008)
- 1 barrel (42 gallons) of crude oil = 5.8 MM Btu
- 1 gallon of gasoline = 124,238 Btu (based on U.S. consumption in 2008)
- 1 gallon of diesel fuel = 138,690 Btu
- 1 gallon of heating oil = 138,690 Btu
- 1 barrel of residual fuel oil = 6.287MM Btu
- 1 gallon of propane = 91,033 Btu
- 1 short ton of coal = 19.977 MM Btu (based on U.S. consumption, 2008)
- 1 kilowatt hour of electricity = 3,412 Btu (by definition in this case).

Many organizations published the conversion factors they use for energy comparisons, such as the Norwegian Petroleum Directorate, the International Energy Agency, etc.

Conversion of gas in boe

For statistics purposes, the conversion of gas into barrels oil equivalent (boe) is generally made *on a calorific value*, using a conversion of approximately 6 Mcf for 1 boe, or the actual conversion factor of the respective calorific values for the specific gas and oil compositions, which may lead to conversion factors in the range of 5.4 to 6.6 Mcf per boe.

Such coefficients do not reflect the relative prices between oil and gas for which the current price ratio is in the range of around 10 and 15 depending on the regional markets.

8.2 Appendix 2– Main natural gas related definitions

Obtaining a good understanding of gas definitions and concepts is paramount for defining an appropriate gas strategy and communicating with the gas industry.

Natural gas is made of a naturally occurring mixture of hydrocarbon (constituted of carbon and hydrogen) and nonhydrocarbon gases. It is part of the family of *hydrocarbons* or *petroleum* which includes *natural gas* and *crude oil*. Both exist in natural underground reservoirs or formations but have their own specificities.

Natural gas may exist in underground reservoirs in two forms: associated or nonassociated gas.

- ***Associated gas*** corresponds to natural gas that occurs with crude oil, either as free gas located above reservoir oil (*Gas Cap Gas*), or in solution dissolved in reservoir oil (*Solution Gas*) and that is liberated from solution by reduction in pressure and temperature. On average, near 30% of the worldwide gas production consists of associated gas and this share is decreasing.

  From a legal and regulatory point of view, the reservoir containing both oil and associated gas is generally classified as an *oil reservoir* or an *oil field* containing several oil reservoirs.

  In some countries (such as the US and Canada), a production well will be classified under the applicable regulations as either an *oil well* or a *gas well* depending on the quantity of gas produced along with oil–the so-called *Gas/oil Ratio* (GOR)–with consequence on the authorized well spacing.

  Most of the energy of the gas cap is required for maximum oil recovery. Therefore, under energy conservation good practice, associated gas production from an oil reservoir or well must be carefully planned and monitored. *Re-injection* in the reservoir–through gas reinjection wells–of the gas extracted when producing oil instead of the immediate sales of such gas may be justified for pressure maintenance, or to prevent gas flaring or venting, as explained in Section 3.1.2.

- ***Nonassociated gas*** consists of natural gas found in a natural reservoir that does not contain crude oil.

  However, some liquid hydrocarbons components may generally be extracted from nonassociated gas, as from associated gas, after an appropriate surface separation and processing. The most common liquid component is called *condensate* or *condensate lease* or *natural gasoline*, a form of very light oil having a specific gravity higher than 40 ° API. The *condensate/gas ratio* (GCR) may vary from about 10 to 100 bbl/MMcfd.

  From a legal and regulatory point of view, the reservoir containing nonassociated gas is generally classified as a *gas reservoir*–or a *gas field* combining several gas reservoirs–or when sufficient condensate is present as a *gas condensate reservoir or field.*

  Under good reservoir engineering practice, gas re-injection of the produced nonassociated gas after extraction at the surface of the liquid components of the nonassociated gas, a process call *gas cycling*, may be justified during a first phase of production in order to maximize the recovery of liquids from the gas and prevent the deposition of a liquid fraction in the reservoir by a too rapid pressure drop.

The composition of natural gas varies from reservoir to reservoir, and may also vary during the production period, in particular for the petroleum liquid concentrations. The *calorific value* or *heating value* of a given volume of natural gas depends on its composition, and therefore the selling price for a unit of volume of gas.

Depending on its composition, natural gas, either associated or nonassociated, may be subclassified as:

- *Dry gas*: Gas containing little or no hydrocarbons commercially recoverable as liquid product. It consists mainly of methane.
- *Wet gas* or *rich gas*: unprocessed natural gas or partially processed natural gas produced from a reservoir containing condensable hydrocarbons, also called condensate or more generally natural gas liquids.
- *Sweet gas*: Gas found in its natural state, containing small amounts of compounds of sulphur that it can be used without purifying.
- *Sour gas or acid gas*: Gas found in its natural state, containing such amounts of compounds of hydrogen sulphide (H_2S) or carbon dioxide (CO_2) as to make it impractical to use, without purifying, because of its corrosive effect on piping and equipment and environmental impact. Sour gas generally corresponds to H_2S concentration above 100 parts per million and/or CO_2 concentration above 2%.

Natural gas produced at the wellhead (named the *raw gas*) requires specific processing prior to its transportation, carried out in a *gas processing facility* or *plant*. Depending on the gas composition, many products may be extracted from the natural gas in addition to methane, such as: ethane, propane, butane, and heavier components referred to as condensate or natural gasoline; as well as nonhydrocarbons components including sulphur, carbon dioxide, helium... The gas resulting from processing is called *sales gas* or *residue gas*.

For interpretation of legal and contractual documents related to natural gas, the definitions of petroleum, oil and gas are critical. In most cases, *petroleum* or *hydrocarbons* means a reference to liquid petroleum and corresponds to crude oil as well as the liquids extracted from gas; *natural gas* means wet and dry gas. The following definitions used in the 2008 Egypt model agreement are common in the industry for petroleum, oil, and gas:

- *" "Petroleum" means Liquid Crude Oil of various densities, asphalt, Gas, casinghead Gas and all other hydrocarbon substances that may be found in, and produced, or otherwise obtained and saved from the Area under this Agreement, and all substances that may be extracted there from.*
- *"Liquid Crude Oil" or "Crude Oil" or "Oil" means any hydrocarbon produced from the Area which is in a liquid state at the wellhead or lease separators or which is extracted from the Gas or casinghead Gas in a plant. Such liquid state shall exist at sixty degrees Fahrenheit (60°F) and atmospheric pressure of 14.696 PSIA. Such term includes distillate and condensate.*
- *"Gas" means natural gas both associated and nonassociated, and all of its constituent elements produced from any well in the Area (other than Liquid Crude Oil) and all nonhydrocarbon substances therein. Said term shall include residual gas, that gas remaining after removal of LPG."* [Therefore under this definition the

nonhydrocarbon substances such as helium, CO2 or sulphur are included under the agreement and can be sold by the agreement-holder].

***Petroleum operations* generally consist of operations related to both oil and gas–associated and nonassociated–unless otherwise defined**. Useful definitions on gas may be found in relevant oil and gas glossaries available on the web.

Definitions for the following terms frequently used in any gas document are provided for convenience:

- *"LNG*" means "liquefied natural gas" consisting mainly of liquid methane (CH_4) obtained from an LNG plant. Natural gas is liquefied in a "LNG plant" by cooling it to minus 161 degrees Celsius. LNG occupies one six-hundredth of its original volume, making it economic to transport by LNG tankers to customers around the world. Once delivered, LNG is re-gazified for use by many industries, including electricity generation, fuel for transport and home heating and cooking.
- "*LPG*" means "liquefied Petroleum Gas, which is a mixture principally of propane (C_3H_8) and butane (C_4H_{10}) liquefied by pressure and temperature and obtained from processing in a specific "LPG plant."
- "*NGL*" means "natural gas liquids" and corresponds to all the liquids obtained during natural gas production and processing, and consisting of ethane (C_2), propane (C_3), butanes (C_4) and condensates (C_{5+}) including natural gasoline, a light, volatile liquid hydrocarbon mixture recovered from natural gas.
- "*Condensate*" consists of those liquids obtained from natural gas consisting of a mixture of C_{5+} hydrocarbons. Condensate quantities include both *field condensate* separated at the field and *plant condensate* extracted from a processing plant.
- "*GTL*" means "gas to liquids" and corresponds to the conversion of gas into liquids, the "GTL products", through a dedicated "GTL plant".

NGLs are generally included in statistics under oil production and often considered as "oil" for interpretation purposes[16]. Their importance grows in the world. For example, in the US, NGLs amount to over one fourth of the total US oil production, while on a worldwide basis their share represents over 10% of the oil production.

A great care should be given to the definitions in gas documents and agreements to prevent misinterpretations of legal and contractual arrangements related to gas. Such definitions should be clear, precise and accurate. As an example, the following definitions from the *UK Gas Act* are illustrative of the technicalities to be given to gas definitions for facilitating future interpretations:

- *" "gas" means any substance which consists wholly or mainly of:*
    - *methane, ethane, propane, butane, hydrogen or carbon monoxide;*
    - *a mixture of two or more of those gases; or*
    - *a combustible mixture of one or more of those gases and air.*
- *"gas processing facility" means any facility which carries out gas processing operations;*
- *"gas processing operations" means any of the following operations, namely:*
    - *purifying, blending, odorising or compressing gas for the purpose of enabling it to be introduced into a pipe-line system operated by a public gas transporter;*

[16] However, the currently applicable rules for the determination of OPEC oil quota exclude condensates and NGLs from the oil production figures.

- *removing from gas for that purpose any of its constituent gases, or separating from that gas for that purpose any oil or water; and*

- *determining the quantity or quality of gas which is or is to be so introduced*."

The conditions of pressure and temperature for measurement must be stated when a volume of gas is expressed in a document. The following definitions from the 2008 Egypt model agreement correspond to a case where the Anglo-Saxon units system applies for defining the *standard conditions (S)* of measurement for all purposes under the agreement:

- *"Standard Cubic Foot (SCF)" is the amount of Gas necessary to fill one (1) cubic foot of space at atmospheric pressure of 14.696 PSIA at a base temperature of sixty degrees Fahrenheit (60°F).*
- *"BTU" (British Thermal Unit) means the amount of energy required to raise the temperature of one (1) pound of pure water by one (1) degree Fahrenheit from sixty degrees Fahrenheit (60°F) to sixty one degrees Fahrenheit (61°F) at a constant pressure of 14.696 PSIA.*
- *"Barrel" shall consist of forty two (42) United States gallons, liquid measure, corrected to a temperature of sixty degrees Fahrenheit (60°F) at atmospheric pressure of 14.696 PSIA.*

When the metric system is used (as in Norway, Algeria and many more countries), standard conditions correspond to a temperature base of 15° Celsius and a pressure base of one bar, *i.e.* the atmospheric pressure. In some cases, gas volume is also measured at *normal conditions* (N) corresponding to a temperature base of zero degree Celsius.

8.3 Appendix 3 – Estimating and classifying natural gas resources and reserves

In order to prevent misinterpretations on the amount of gas available with reasonable certainty for a commercial project it is of paramount importance both for policy-makers and investors to **understand the concepts of *Reserves* and *Resources* along with their classification in categories depending on the level of uncertainty**. The estimated volume of gas which may be produced and sold in the future from the field or group of fields allocated to a project is the key variable for determining the economics of the project. Regarding a country, knowing the estimates of reserves and resources per field, region or for the entire country is the first step in designing a gas policy and strategy.

Gas discovered or to be discovered and the corresponding NGLs must be classified in terms of reserves and resources in relation to the degree of uncertainty on the estimated gas volumes and in addition for resources in relation to a risk element, the chance of discovery.

Gas Reserves and gas Resources correspond to quite different concepts in the industry which have to be fully understood for preparing more accurate gas feasibility and market studies. **Several definitions and classification systems have been published** by countries, institutions or agencies, each one with its own definitions and standards leading to differences in estimated volumes.

The most used system in the world today is the *Petroleum Resources Management System* (PRMS) published in 2007 by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE). The PRMS defines the major recoverable reserves and resources classes: *production, reserves, contingent resources, prospective resources,* as well as *unrecoverable petroleum.* Reserves are further categorized as *proved, probable* or *possible reserves* in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status (see the following Box 5).

The SPE/WPC/AAPG/SPEE petroleum resources classification system which applies to petroleum, *i.e.* both oil and gas, is graphically presented in Figure 1. The horizontal axis represents the "*Range of Uncertainty*" on the recoverable quantities for a project, while the vertical axis represents the "*Chance of Commerciality"*, the chance that the project will be developed and reach commercial producing status.

For gas discoveries and fields the key question is when contingent resources already discovered can be classified as reserves. Such date is related to the degree of certainty that a *commercial gas development* exists and that the decision to carry out such development project is taken–what is called the *final investment decision* (FID)–or will be taken in a relatively short period. Criteria for classifying as Proved Reserves are that the FID was taken and that the host government has approved the gas development. **The feasibility of a gas development project is generally assessed only on the total Proved and Probable Reserves** as estimated at the date of the decision and certified by a recognized and independent reservoir engineering firm**.**

Box 5: Oil and Gas Resources and Reserves Definitions

The following are illustrative excerpts of definitions for the most used concepts in the 2007 PRMS classification system:

"Resources means all quantities of all types of *petroleum*, discovered *and undiscovered* (recoverable and unrecoverable), plus those quantities already produced.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of *development projects* to known accumulations *from a given date forward* under defined conditions.

Reserves must further satisfy four criteria: they must be *discovered, recoverable, commercial, and remaining* (as of the evaluation date) *based on the development project(s) applied.*

Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with *reasonable certainty* to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered.

If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P).

In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves.

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario.

In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

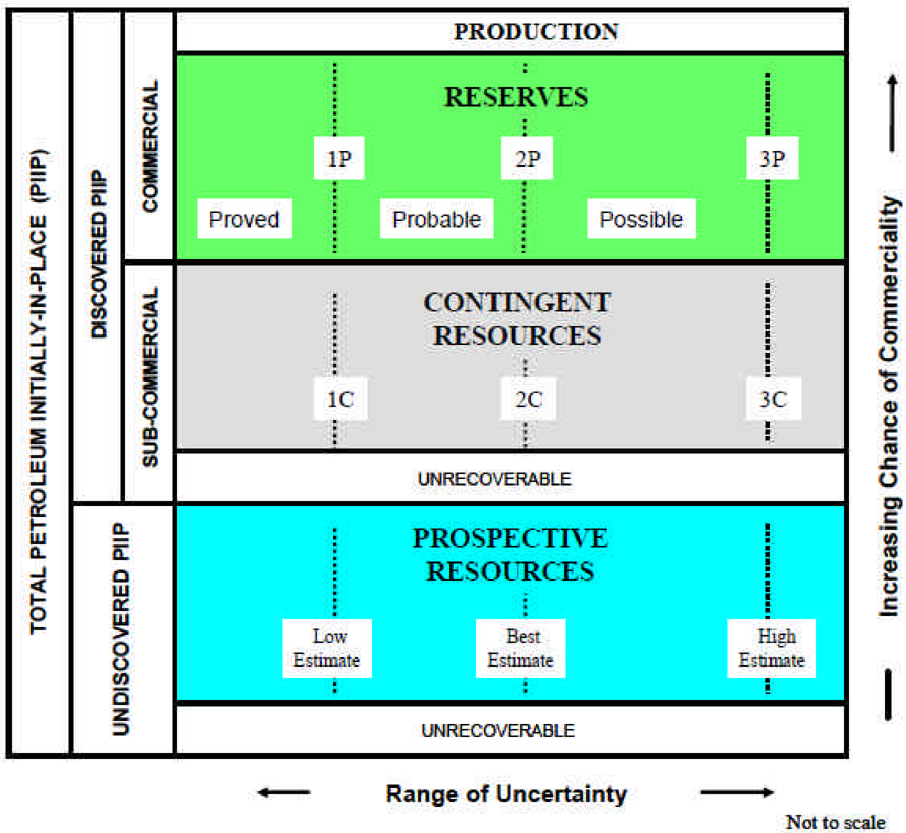
Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations (*i.e. already discovered*), *that cannot be classified as Reserves* because the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Production is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources and reserves are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage. As a consequence, annual gas production statistics should therefore indicates the category of production published, ideally with its subdivision into marketed gas production, raw gas production, flared production, re-injected gas, etc."

Source: SPE/WPC/AAPG/SPEE

Figure 1: The Petroleum Resources Classification System
(Source: SPE/WPC/AAPG/SPEE)



The reserves for a gas field generally consist of two estimated volumes per reserves category, first for dry gas and second for natural gas liquids, when the gas is sold after extraction of liquid volumes, and not as wet gas:

- The ***dry gas reserves*** (expressed in cm or cf), corresponding to *sales gas* or *marketable* quantities after processing. Such reserves are a percentage, called “gas recovery factor”, of the gas-initially-in-place (GIIP) generally in the range of 60 to 80% of the GIIP for conventional gas–lower for unconventional gas–a percentage higher than the average recovery factor for oil.

  When gas production is temporarily re-injected into a reservoir for pressure maintenance or recycling–for example for increasing the extraction of liquids, or when the unused associated gas is re-injected in order to prevent its flaring up to the availability of a market for it–and when the gas will eventually be produced and sold, the re-injected gas volume estimated as eventually recoverable and marketable may be included as Reserves.

  Lowering the wellhead abandonment backpressure and adding compression before transmission of the gas increase the portion of in-place gas that can be commercially produced and the production duration under the planned long term field development plan and therefore the Reserves estimates.

- The ***condensate and LPG reserves*** (often expressed in MMbbls), corresponding to the natural gas liquids which may be extracted from wet gas after separation and processing. The sale of such condensates and LPG may significantly increase the incomes generated from gas production under a given gas agreement. Any hydrocarbon liquids separated from the wet gas subsequent to the agreed sales point is not reported as Reserves by the producer.

In conclusion and in accordance with good petroleum practice, **gas reserves only exist when the commercial viability of a given gas development project is demonstrated by appropriate technical and economic studies and a decision** for their development is taken or envisaged shortly. Thus, the PRMS system states the following:

> "*In order to have gas Resources to be classified as Reserves a gas project (as any oil project) must be sufficiently defined to establish its commercial viability.*
>
> ***There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame**.*
>
> *A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project.*
>
> *While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented*."

Therefore, the monetization of the discovered gas resources under a commercial gas development project must be demonstrated to be in a position of dealing with natural gas Reserves.

8.4 Appendix 4 - Gas outlook: a sustainable growth

8.4.1 The rapid growth of gas production and consumption

The world gas consumption and *net* marketed production *doubled* between 1980 and 2009, growing from around 1,450 Bcm to 3,100 Bcm (110 Tcf). The 10 main gas producing, exporting or importing countries are listed in Table 3 for the year 2009. For comparison, the equivalent *gross* gas production in 2008 was around 3,800 Bcm when adding to the marketed production, the quantities of re-injected gas into the reservoirs, flared gas, gas used in petroleum operations and gas shrinkage under liquids extraction.

Indeed, when looking to *gas consumption* the increase was more abrupt for the non-OECD countries, with a trebling consumption during the period from 500 to 1,500 Bcm. If we look at the developing countries only, excluding from non-OECD countries the CIS countries, the gas consumption growth is considerably higher, rising from 170 Bcm in 1980 to over 900 Bcm in 2008. Thus, *the share of the developing countries in the world consumption rose from 12 % to 32 % in less than three decades*.

Table 3: The 10 main gas producing, exporting and importing countries in 2009 (Source: IEA, Key World Energy Statistics 2010)

Gas producing country	2009 Net production (Bcm)
USA	594
Russia	589
Canada	159
Iran	144
Norway	106
China	90
Qatar	89
Algeria	81
Netherlands	79
Indonesia	76
Rest of the world	1094
World	**3101**

Gas exporting country	2009 Net exports (Bcm)
Russia	160
Norway	100
Canada	76
Qatar	67
Algeria	55
Indonesia	36
Netherlands	30
Turkmenistan	27
Malaysia	24
Trinidad & Tob.	21
Rest of the world	140
World	**736**

Gas importing country	2009 Net imports (Bcm)
Japan	93
Germany	83
USA	76
Italy	69
France	45
Ukraine	38
Turkey	35
Spain	34
Korea	33
UK	29
Rest of the world	214
World	**749**

When considering the evolution of the *net gas production* in the non-OECD developing countries only, excluding the CIS countries, the rise is even higher than for consumption going from 190 to 1,150 Bcm during the same period, with a share in the worldwide production growing from 13% to 37%. As a consequence the *gas exports* from such developing countries to the developed world jumped from 21 Bcm in 1980 to 225 Bcm in 2008. The above figures illustrate that more and more gas was monetized in the developing countries which possess large gas resources and reserves.

8.4.2 The recent development of LNG projects

The development of LNG exports mostly from the Middle East, Africa, Australia and Latin America is impressive. The existing world LNG capacity is near 275 MMtpa at the end of 2010 for the 30 existing LNG plants–excluding the 6 new plants under construction and the more than 20 plants under study–instead of around 100 MMtpa in 2000. As a result, the share of LNG in international gas trade is increasing, now about 30% on a worldwide basis. This share is planned to continue to rise up to 40% in the next 25 years.

Of the 17 countries holding today LNG plants on stream, 14 are non-OECD countries. The developing countries represent over 92% of the currently LNG capacity already built, as illustrated in Table 4. The reason for the predominant weight of the gas developing countries in LNG projects is that this transportation solution is well appropriate for exporting gas when the distance between the producing fields and the consuming markets is long, generally speaking over 4,000 km (however LNG may also be justified when distance is shorter depending on pipeline costs). Thus, LNG represents for developing countries a cost-benefit solution to unlock stranded gas resources and monetize them when the local gas demand is insufficient.

Table 4: The 17 LNG producing countries at the end of 2010

Category	Region	Country	LNG capacity (MMtpa, in operation end 2010)
OCDE	Australasia	Australia	14.7
	Europe	Norway	4
	North America	USA (Alaska)	1.5
Non-OCDE	Africa	Algeria	24
		Nigeria	23.5
		Egypt	12.2
		Equatorial Guinea	3.7
	Latin America	Trinidad & Tobago	15
		Peru	4.4
	Middle East	Qatar	77
		Abu Dhabi	8
		Oman	3.7
		Yemen	6.7
	Asia	Indonesia	42
		Malaysia	23
		Brunei	7.5
	CIS	Russia (Sakhalin)	9.6

The recent growth of LNG markets combined simultaneously with the occurrence of unforeseen events had a major impact on gas prices. Three main events occurred at the same time: the accelerated expansion of LNG capacity in the last years, the recent and rapid development of unconventional gas in North America allowing the USA not to import LNG as previously planned, and the economic crisis of 2008 leading to a short-term reduction in the energy demand.

The consequence of the combination of all those events was the change from a seller's gas market to a buyer's market due to the current gas capacity surplus on the international market, explaining the temporary drop in gas prices observed in some markets, especially in North America. This short term situation will change in the course of the coming decade by the development of the gas demand.

8.4.3 Future outlook for natural gas

In a lower carbon energy world necessary for mitigating the climate change, the demand for gas will continue to rise, especially if carbon taxes are introduced in the world on power generation. This would grant to gas–which benefits from a lower carbon content that other fossil fuels, especially coal–a higher competitive advantage.

Most recent forecasts estimates that the gas demand should reach 4,250-4,500 Bcm by 2035, an increase of 40 to 50% relative to 2008, with a share of gas in the primary energy mix of 21%. Around 80% of the increase in gas demand may come from non-OECD countries.

The main drivers for the development of gas production/consumption are:

- *The gas government policies* adopted by the producing and consuming countries, for example in terms of carbon tax policy, encouragement to foster gas exploration and development, processing, transmission and distribution activities, timely award of the required licences and contracts, conditions of access to new gas resources such as unconventional gas, etc.
- The *gas prices* relative to other competing energy sources.
- And the rate for *economic growth*.

Reserves and resources are sufficient to support such gas developments if the required investments are made in a timely fashion. The world *proved gas reserves* amounts to over 180 Tcm (6,500 Tcf) at the end of 2009, corresponding to near 60 years of production at the current rate. Gas proved reserves have more than doubled since 1980 when they amounted to 80 Bcm. The gas cumulative production represents today around only 35% of the current gas proved reserves, showing that this industry is in its early stages of development. For comparison, when regarding oil this percentage reaches over 70% showing that gas has proportionally been less produced and used.

Gas resources are considerably higher than the only current gas proved reserves. According to recent estimates published by IEA, *remaining* recoverable resources of conventional gas (including the proved reserves) exceed worldwide "*400 Tcm, equivalent to almost 130 years of production at current rates. In addition, unconventional gas resources in place are estimated at more than 900 Tcm and more than 380 Tcm of this gas is likely to prove recoverable*."

8.5 Appendix 5 – Presentation of gas experience in six selected countries

The following highlight six illustrative developing country cases of gas monetization addressing quite contrasting contexts:

- **Côte d'Ivoire**, a country with only medium size gas reserves which decided to promote their exploitation for supplying the local markets only, mainly for power generation.
- **Equatorial Guinea**, where the large nonassociated gas reserves were progressively monetized over time, first for exports through a methanol plant and then an LNG plant and now also for local needs.
- **Yemen**, an oil exporting country where the associated gas was reinjected during 20 years, until an export LNG plant was built by new investors.
- **Papua New Guinea**, a case with stranded gas resources which waited for several decades their exploitation until a major LNG export project was decided.
- **Egypt**, one of the most successful gas stories in the world, which demonstrates that the introduction of a drastically revised gas policy encouraging gas exploration and utilization led to the discovery of quite large gas reserves now developed for supplying mostly the local markets with the balance exported.
- **Nigeria**, on the contrary, the example of a country with major gas resources which did not adopted for a long time the appropriate gas policy and where a large share of the associated gas is still flared. Only in 2008 a modern gas policy was decided.

The gas policy adopted by each of the above country is specific in terms of gas investments and resources–from gas supply-limited countries to large exporters–available local markets and energy mix requirements. The experience gained by those countries is of great interest, bearing in mind however that in the future, in a world focusing on lower carbon sources of energy to limit climate change, monetization of gas resources should be easier to achieve than in the past.

For a better understanding of possible gas development strategies and options each of the country cases briefly highlights the nature of their main gas projects, their size, the gas uses domestically or abroad, the main actors involved and the applicable contractual arrangements. The main difficulties encountered in deciding for the country gas projects and in finding gas purchasers willing to commit for long-term purchase contacts are also summarized.

8.5.1 Côte d'Ivoire: medium size gas resources for local gas markets

Côte d'Ivoire is the example of a country which successfully implemented an efficient policy and strategy to promote the development of relatively medium-size gas resources for supplying the local markets, mainly for power generation.

According to a 2001 ESMAP report, "***Côte d'Ivoire is one of the few Sub-Saharan African (SSA) countries … which uses natural gas in its domestic market****. It holds, however, a distinctive role among SSA* [Sub-Saharan Africa] *countries, as it is the first (and to-date [2001], the only) one that has developed a comprehensive vision of gas utilization across a wide range of economic activities. In spite of its recent gas history, Cote d'Ivoire is using gas locally as its main energy carrier for thermal power generation and in the refinery, is building a gas network in Abidjan's industrial suburbs to supply conventional industry*."

The development of a domestic gas market results from the pro-active policies which were implemented by the country at the end of the 1980s and in the 1990s to encourage petroleum investments, including the following actions related to natural gas:

- First, an international promotion of the Foxtrot gas and condensate field was decided by the country in 1990 to attract the private sector. The field, located offshore at only 80 km from the capital Abidjan, was discovered in 1981 by Phillips Company and its partners which relinquished the area in 1989 because the venture did not succeed after several years in signing a gas contract with potential gas users. One of the reasons was that the electricity company gave at that time higher priority to hydropower relative to gas generation and was not prepared to commit for gas.
- As a result of this promotion, a gas development contract in the form of a production sharing contract (PSC) containing *adhoc* gas provisions for developing the Foxtrot field and building a gas pipeline system from the field to Abidjan, along with further exploration, was signed in 1994 with a consortium of several companies including Petroci, the NOC, which holds an interest of 40% in the Foxtrot field area and 10% in the surrounding exploration area. An initial gas sales contract–including take-or-pay obligation up to 70 MMcfd–was signed in 1997 with several consumers for three types of gas uses: (1) generating power at two plants, (2) replacing fuel at the Abidjan refinery and (3) for industrial purposes. The gas field, a medium-size field with initial certified reserves of around 20 Bcm (0.6 Tcf), was developed for a $200 million investment and started to produce in 1999, 18 years after its discovery. An exclusive exploitation authorization was awarded in 1997 under the PSC for an initial 25-year term which may be extended for 10 years. Additional development investments for new production wells in the block started in 2008 to increase the production to 105-180 MMcfd under an extended gas sales contract.
- Second, an international promotion of exploration acreage, leading to the signing of several PSCs, was launched. The model PSC retained for the promotion provides *inter alia* for appropriate gas provisions encouraging gas exploration and development in case of discovery. As a result, a gas & condensate field (the Panthère field) and an oil field holding associated gas (the Lion field) were put on stream in 1996. A pipeline built by the PCS-holder transport the gas to Abidjan where it is sold to a State agency for power generation.
- Third, the government adopted a gas policy favouring the development of gas-fired power generation in Abidjan relative to gasoil-fired power and hydropower. To that end, decisions were made to build, with the involvement of the private sector, three new power plants in Abidjan: a first one in 1995 of 99 MMW (the Ciprel project), a second in 1997 of 110 MMW–funded with World Bank financial assistance under the Private Sector Energy Project–and a third from 1999 of 420 MMW (the Azito project, the then largest gas-fired thermal power plant in SSA), built and operated under a 23-year Build, Own, Operate and Transfer (BOOT) concession.

By the end of 2009, the cumulative Ivoirian gas production exceeded 21 Bcm (750 Bcf). To accompany the local demand growth, the annual gas production reached 100 MMcfd for the first time in 1998 and is currently around 160 MMcfd, three times the initial estimates made in the early 1990s. Gas is primarily used for power generation, which was the key driver for deciding on the first gas development project. In addition, gas is sold–around 20 MMcfd–to the SIR refinery, where it replaces fuel oil and butane, and to the local industrial sector as a fuel. Moreover, the LPG recovered from gas is sold locally to households as energy for cooking, thus reducing the deforestation.

8.5.2 Equatorial Guinea: a long story until the first export LNG plant

Equatorial Guinea is now an established oil and gas exporting country. Its petroleum development was long to emerge; starting with a non-associated gas discovery initially considered as uneconomic and now exploited, mainly for supplying an export LNG plant and to a small extent for local needs.

The large Alba gas and condensate field, located 32 km offshore and covering 101 km2, was discovered in 1983 and then relinquished by the discovering company. The area was again awarded by the government in 1990 under a PSC to a new private company which started a small gas production in 1991 and proved additional gas reservoirs. Now, after several stages of development and the building of downstream infrastructure, the Alba field is producing, from 19 wells, 800 MMcfd, 57,000 bpd of condensate and 18,000 bpd of LPG. In addition, 3.4 MMtpa of LNG and 19,000 bpd of methanol are exported.

The following summarized the main elements of the Alba gas project, in particular related to the creation and phased development of various gas markets, locally and abroad, for increasing commercial utilization of the Alba gas:

- The first stage of development consisted in the production of 65 MMcfd for the recovery of 6,000 bpd of condensate, with all the remaining gas being flared.
- In a second stage, onshore gas processing facilities were built along with a gas line to re-inject into the reservoir the balance of the processed gas not used in supplying several gas utilization projects, and thus minimizing the gas flaring. The gas so re-injected in the field is not lost and will be produced in the future.
- Third, the first local gas utilization other than fuel for petroleum operations started in 1999 for power generation (10 MMW expanded to 27 MMW in 2004).
- Fourth, a LPG extraction plant was built and then expanded in 2004, with a capacity of 20,000 bpd. The plant is owned by a special purpose company in which some of Alba PSC holders and the State have an interest.
- Fifth, a methanol plant converting 130 MMcfd of dry gas into 19,000 bpd of methanol was put on stream in 2001. Such methanol is exported by ships and is used in petrochemical plants abroad. The methanol plant is owned by a special purpose company, AMPOL, and governed by a specific arrangement. Its shareholders consist of two of the companies holding the Alba PSC (Marathon at 45% and Noble Energy at 45%) and the State, initially represented by the national oil company GEPetrol and now by Sonagas GE SA, the national gas company of Equatorial Guinea created in 2005 which is responsible for diversification of gas activities.
- Sixth, the last major stage was the construction of a one-train 3.7 MMtpa LNG plant operational in 2007, a $1.4 billion investment, the second LNG plant in SSA. The plant is owned by a special purpose company, EG LNG, the shareholders of which are one of the PSC holders, Marathon (60%), the State (25%, thru Sonagas GE SA), and two Japanese companies for 15% (Mitsui and Marubeni). All produced LNG from the first train of the plant is sold FOB to BG Gas Marketing Limited, a BG Group affiliate, under a 17-year LNG Sales and Purchase Agreement. Destinations of LNG are selected on a case-per-case basis by BG.

The planned next step is the construction of a second train at the LNG plant, planned to use gas from other fields in Equatorial Guinea and possibly from neighbouring countries, in particular from Cameroon and Nigeria where stranded gas exists.

8.5.3 Yemen: using mostly associated gas in an LNG plant

This country is an example of an oil exporting country having the challenges since 1986, the first year of oil production in the country, of monetizing associated and non-associated gas resources. The decision to market the gas was only made near twenty years later. It involved the construction by the private sector of a pipeline for supplying an LNG export project along with the opportunity of having around 10% of the gas reserved to supply the domestic market, in particular for power generation and LPGs.

The main features of gas monetization in Yemen consist of the following steps from the starting of the associated gas production in 1986.

- The Yemen gas resources are mostly associated gas from the onshore Marib block 18, east of Sana'a in central Yemen, the main oil producing block in the country on stream since 1986 which produced over 1 billion barrels. This block was held under a PSC by a consortium of companies until November 2005, the expiry of the agreement.
- Thereafter, the government decided not to renew the exploitation authorization, taking over the operations through a Yemeni state-owned operating company named SAFER Exploration & Production. From the start of the production, the unused associated gas was re-injected in the reservoirs, waiting for its monetization. The certified gas reserves of block 18 were estimated to around 280 Bcm (or 10 Tcf, consisting of 9.15 Tcf of proved reserves, 0.7 Tcf of probable reserves). For the time being, 1 Tcf was reserved for domestic market.
- A special purpose company, Yemen LNG (YMLNG), was created with new investors for monetizing the discovered gas, namely the following seven shareholders: Total 39.62%, the project leader), Hunt Oil (17.22%, the company which discovered oil in 1984 in Block 18), two Korean LNG buyers, the SK Corporation (9.55%) and KOGAS (6%), Hyundai (5.88%, one of the block 18 PSC-holders), and two Yemeni companies holding 21.73%, Yemen Gas Company (YGC, which is a state-owned company constituted in 1993 to promote gas utilization in Yemen and responsible for bulk distribution of LPG, for 16.73%) and the General Authority for Social Security & Pensions (5%). The revenues for the shareholders will come from the dividends paid by YMLNG.
- After years of studies, the $4.5 billion project proposed par YMLNG was approved in August 2005 by the Yemeni government. The project consist of four main components for gas exports and local sales, the produced gas being supplied by the State to YMLNG at the field:
  - Construction of additional gas production and processing facilities in block 18, the producing fields remaining operated by SAFER with an oil production of 320,000 bpd in 2008. The new facilities under the project include a 25 km, 20-inch transfer line linking the two gas processing units.
  - Laying of a 320-kilometer 38" pipeline to carry the gas across the desert to Yemen's southern coast.
  - Building an industrial complex in Balhaf comprising a 2-train gas liquefaction plant with a capacity of 6.7 MMtpa, requiring feed gas at the rate of 1,140 MMcfd, storage tanks and an LNG export terminal serving world markets. First cargo was loaded in 2009 after four years of construction works.
  - For local markets, construction of an additional 12,000 bpd LPG plant and storage in block 18 as well as a spur line from Marib to Ma'abar to feed a new gas-fired power plant at a rate of 100 MMcfd.

To implement the project a series of agreements were entered into, in particular the following:

- *A Gas Agreement* was signed between the Yemeni government and YMLNG and approved by the parliament. It also provides for the fiscal regime, which include a progressive tax income starting at 25% and which may reach 90% when specific criteria are met.
- *A Gas Supply Agreement* (GSA) was signed between the Yemeni government as seller of the feed gas to the LNG plant and YMLNG, providing *inter alia* with the purchase price of the gas from block 18 and the allocation of the block costs between SAFER (responsible for the costs related to oil) and YMLNG (responsible for the costs related to gas). Under the GSA, Yemen LNG is granted *exclusive rights* to the gas produced from the reservoirs of the Marib area fields in block 18, corresponding to the dedication to the project of the gas production to supply up to 12.5 Bcm of gas per year.
- For selling the LNG, *three 20-year Gas sales and Purchase Agreements* for a total of 6.7 MMtpa were signed in August 2005 respectively with KOGAS, GDFSuez and Total Gas & Power to serve the main consumers markets for LNG, both in the Asia Pacific basin and on either side of the Atlantic. According to the company. The marketing strategy of Yemen LNG was "to obtain a mix of sales between an Asian contract which provides good stability and security of revenue and US contracts which have more potential upside but less stability". To illustrate the diversified marketing, in 2010 Yemen LNG deliveries reached ten countries.
- *The project finance agreements* as YMLNG was financed at 40% by equity provided by the shareholders and 60% by loans ($2.6 billion) provided by commercial banks and financing institutions.

8.5.4 Papua New Guinea: converting stranded gas into a major LNG project

Papua New Guinea is an illustrative case of a country were several large and medium-size **gas and condensate** discoveries (such as Hides, Angore and Juha) were made during the last 50 years and were stranded for several decades due to economic reasons and the difficulty to find domestic and international markets for the discovered gas.

However, after several unsuccessful attempts for marketing the gas in Australia, a first commercial gas development project was decided in 2010, taking benefit of the new high gas price context in Asia and by integrating under an unitization agreement the additional volumes of gas from several companies operating within the same region of Papua New Guinea, The project is based at the date of decision on the availability of estimated gas reserves of 9.3 Tcf (proved and probable) from **seven unitized onshore fields**, combining non-associated gas fields and associated gas from Kutubu, Moran and Gobe oil fields.

The project is an LNG gas export project, called the *PNG LNG Project* involving in its first phase the construction of a 2-train 6.6 MMtpa plant. *The PNG LNG Project*, planned to be on stream at the end of 2014, will collect, process and transport in its initial phase gas from fields located in several exploitation licences held by various consortia.

The option of exporting the gas by pipeline to Australia, initially envisaged up to 2006, was abandoned as Australia became a gas exporting country. Under the project, LNG and LPG will be exported under long-term purchase contracts to three Asian countries, Japan, China and Taiwan. Condensates will be sold on international markets. For the time being, no significant utilization of the gas in the country is anticipated.

The following characteristics of the project have to be highlighted, in particular in terms of **the series of agreements and approvals which were required for such a paramount project**, dealing with all legal, regulatory, fiscal, socio-environmental, administrative and operational matters, such as the following:

- The project is *an integrated upstream natural gas and LNG plant*, based on a common ownership structure of a special purpose venture governed by a *joint operating agreement* which provides for the designation of the operator selected among the partners. One of the benefits of such unitization of interests is to minimize possible conflict of interest between the various partners involved across the supply chain composed of the following segments from the wells to the gas buyers: upstream (field developments and central processing plants, with gas supplied from various licensees); a condensate pipeline; a 715 km onshore and offshore gas pipeline from the main upstream processing plant to the LNG plant located near Port Moresby; the LNG liquefaction plant, storage and loading facilities; LNG supplies and shipping.
- A *Joint Marketing Agreement* was signed, covering all commercial aspects of the project, including *Gas Supply Arrangements*, *Unitisation Principles* and *Voting arrangements,* aligning all the participants behind the PNG LNG Project. The initial equities of the partners are the following: ExxonMobil (33.2%), Oil Search (29.0%), Santos (13.5%), Nippon Oil (4.7%) and from PNG, the government thru Kroton2 (16.8%) and the landowners thru MRDC (PNG) (2.8%).
- LNG from the project is jointly marketed and was fully contracted to four Asian buyers, comprising TEPCO and Osaka Gas from Japan, CPC from Taiwan and Sinopec from China. The corresponding *LNG Sales and Purchase Agreements* were signed with each of the buyers.
- Prior to making the final investment decision, a specific *Gas Agreement* was signed in 2008 with the PNG government for the project, outlining the fiscal terms under which the Project will be performed and how the project incomes will be shared and taxed. All required legislation and regulatory changes were then passed by the PNG government. The agreement provides for fiscal stability concerning the first 10.5 Tcf, with a maximum marginal tax rate of 41.7%. A two-tier *Additional Profits Tax* triggered at RORs of 17.5% and 20% was introduced in addition to the royalty and corporate tax.
- Moreover, agreements dealing with socio-economic issues regarding the local communities concerned by the project were made, first, between the PNG government and landowners involved in the project for an equitable *Benefits Sharing Agreement* (BSA) and, second, with the PNG government and various licensees for sharing revenues under the so-called multiple individual *Licence Based Benefits Sharing Agreements* (LBSAs).
- Regarding environmental issues, the project is carried out in accordance with the *Project's Environmental Management Plan* approved by the PNG government.
- The project is funded on a debt/equity structure of 70/30. Debt is provided under a project financing base amounting up to $14 billion, one of the largest in the world, dealt with in *financing agreements*.

In conclusion, investment for monetizing the existing PNG gas resources is quite large, amounting to US$15 billion for the initial phase. On an average unit basis, such capital expenditure corresponds to around $1.6/MMBtu. The project will have a major impact on PNG economy, leading to a significant increase in the country's GDP1, and PNG is considering the creation of an offshore sovereign wealth fund (SWF) where part of the project government revenues will be saved. This will mitigate the risk of overheating the local economy when all the government fiscal revenues generated from a major natural resources project are immediately reinjected in the domestic economy.

In the future, two additional LNG trains may be added to the project plant should more gas be found within the project area. Two other LNG export projects identified by other consortia may also be decided for monetizing newly discovered gas resources in the country.

8.5.5 Egypt: a quite successful new gas policy with impressive results

The growth of the Egyptian gas industry has been impressive, following dramatic changes in the country gas policies in the 1980s and 1990s aimed at encouraging more gas exploration, production, domestic utilization and exports. The following figures illustrate the major success of the new gas policy:

- The gas proved reserves jumped from around 80 Bcm (2 Tcf) in 1980 to 1,400 Bcm 40 Tcf) in 2000 and 2,200 Bcm (78 Tcf) in 2010.
- The domestic gas demand increased from 2.2 Bcm in 1980 to 20 Bcm in 2000 and 45 Bcm in 2010 and could reach 56 Bcm in 2015. For gas production, the respective figures are 2.2, 8.1, 21, 64 and 77 Bcm.
- The domestic gas demand being lower than the production, exports started in the last decade and reached 19 Bcm in 2010. Exports are made mostly as LNG since 2005 and by a pipeline to Israel, Jordan and Syria.
- The domestic gas demand is increasing so rapidly that the country decided at the end of 2008 to introduce a two-year *moratorium*, renewed at the end of 2010, *on any **increase** to the current level of gas exports* of near 20 Bcm, priority being now given by the country to the domestic gas markets for supply while remaining in compliance with existing agreements.

The main reasons to explain this great success are the changes periodically brought to the country gas policy to adjust it when requires, the introduction of an attractive gas clause in the PSCs, and the construction of gas infrastructure in the country and for exports. The following actions decided by the government have to be highlighted:

First, in the 1980s and later, Egypt decided to amend the existing PSCs by introducing the so-called *Egyptian gas clause*. Indeed, before this change, in case of nonassociated gas discovery, the PSC-holder had no right to exploit it, because such gas discovery was at that time automatically transferred to the NOC, EGPC. Without any benefit in a gas discovery, the PSC-holder neglected exploration in the gas prospective areas.

- The main purposes of the new “gas clause” under PSCs were to treat gas in a similar manner to oil, giving the right to the company to develop and produce it under the specific economic provisions inserted in the contract, made more attractive than for oil. In 1988, Shell and ENI were among the first companies to be awarded amendments to their original PSCs for dealing with gas. Subsequent changes were introduced in PSCs in the 1990s and 2000s for continuing to encourage exploration and development of gas resources, in particular by defining a more favourable price than before for gas sold to the domestic market.

- Pricing terms for sales to the domestic market were amended several times. Thus in 2008, the government (through EGPC) agreed on new pricing terms for gas produced from the offshore WDDM and Rosetta concessions, the price increase being phased in over the period 2008-2011.
- Thanks to such modern gas clause, exploration efforts were multiplied and more PSCs (176 during the last decade) were signed. Around $35 billion were invested by foreign companies in the upstream petroleum sector during the last decade leading to 489 discoveries of which 178 gas discoveries. In particular, a new oil and gas province was identified offshore the Nile delta in the Mediterranean Sea.

Second, a series a measures were implemented for developing the domestic gas markets with impressive results:

- Transmission and distribution gas networks were built. The national gas grid exceeds now 17,000 km.
- Today, the extracted gas is used by many local sectors: the power generation sector (37 plants), the industrial sector (over 1500 plants), the commercial sector (over 7500 consumers), the residential sector (3.9 million users in 2010 instead of 1 million in 2000), for petrochemicals (ammonia, urea, polystyrene, polyester, etc.), and for transportation as compressed natural gas or CNG (137,000 already converted vehicles may use a network of 129 gas fuelling stations, putting the country in the top 10 CNG-producing countries.
- With the objective of developing the domestic market and focusing on gas activities, upstream and downstream, EGAS (Egyptian Natural Gas Holding Company) was created as an affiliate of EGPC in 2001.

Third, authorizations for LPG exports and gas exports by pipeline or as LNG were granted in the last decade. Thus, a gas pipeline up to Syria was built by the private sector. Two LNG plants for gas exports and LPG plants were authorized, built by the private sector. Moreover, since 2005 the United Gas Derivatives Company (UGDC) joint venture owns and operates the largest natural gas liquids (NGL) extraction plant in Egypt, processing over 1 Bcfd a billion cubic feet of rich natural gas from the East-Nile delta.

- The first LNG plant, *the Damietta LNG plant*, is owned by SEGAS (Spanish Egyptian Gas Company), an investment of $1.3 billion for a one-train 5 MMtpa capacity, on stream since 2005. Its shareholders are Union Fenosa GAS SA of Spain (80%), EGPC (10%) and EGAS (10%), their relationships being governed by a *Participation Agreement*. The capacity of the train is fully booked under 25-year *Tolling Agreements* with the shareholders.
- The second LNG plant, the *Egyptian LNG Trains 1 and 2*, each train having a 3.6 MMtpa capacity (565 MMcfd), is located at Ikdu, with sufficient space at site for a further four LNG trains. The commercial structure of Egyptian LNG has been designed to allow future expansion without the need to involve all existing partners, and third parties may supply gas to the future Egyptian LNG trains. Each train is owned by a special purpose company: El Beheira Natural Gas Liquefaction Company for Train 1 (consisting of BG Group at 35.5%, Petronas at 35.5%, EGPC at 12%, EGAS at 12% and GDFSuez at 5%); and Idku Natural Gas Liquefaction Company for Train 2 (BG Group at 38%, Petronas at 38%, EGPC and EGAS at 12% each).

- All the trains are operated by one company, the Egyptian Operating Company for Natural Gas Liquefaction Projects (Opco). The LNG output of Train 1 has been sold FOB to GDFSuez under a 20-year LNG Sales and Purchase Agreement, with the first LNG shipment lifted in May 2005. The LNG output of Train 2 has been sold FOB to BGGM, a wholly owned BG Group subsidiary, under a 20-year agreement, with the first LNG shipment lifted in September 2005. The gas is supplied for Trains 1 & 2 from gas produced in dedicated fields located in the WDDM concession for processing under a *Tolling Agreement* for each Train.

For the future, new major gas projects are envisaged. Thus, in July 2010 BP and RWE DEA announced an agreement under new terms with the Egyptian Ministry of Petroleum and Egyptian General Petroleum Corporation (EGPC) to develop two “greenfields” with a total capacity of 1 Bcfd located in two deepwater concessions holding total gas proved reserves estimated at 5 Tcf (plus 55 million barrels of condensate) for an estimated $9 billion investment (around $1.8/MMBtu for the capital expenditure component only).

8.5.6 Nigeria: when the enormous gas resources will be used in the country?

To the contrary of the other presented countries cases, Nigeria, a large OPEC oil exporter, did not yet succeed in monetizing all its considerable gas resources. A large proportion of its associated gas is still flared, around 30% instead of 50% in 2000. Such valuable gas is not used for example in lacking gas-fired power plants, due among other reasons to the absence of appropriate gas infrastructure for processing, transporting and distributing gas or for producing electricity.

Reducing gas flaring and monetizing associated and non-associated gas are key priorities for the country. The country holds very large gas reserves capable of increasing gas supplies to both domestic and export markets. The proved gas reserves amount already to 5.25 Tcm (185 Tcf), representing the equivalent of 150 years at the 2008 marketed production level of around 35 Bcm (12.5 Bcm in 2000). The marketed production corresponds to only half of the gross gas production of 70 Bcfd in 2008. Exports as LNG exceeded 20 Bcm in 2008, while over 15 Bcm of gas was flared, a quantity higher than the current 14 Bcm local demand (of which 80% correspond to the power generation sector). Only part of the associated gas is saved by re-injecting it in oil reservoirs for improving oil recovery and could be produced later for future utilization.

In this context, the demand for gas in Nigeria may rapidly increase should an appropriate gas policy be efficiently implemented with continuity by the country, which was not the case in the last decades. In 2008 the federal government announced **a new gas policy, called the *Nigerian Gas Master Plan (*NGMP)**, involving three elements for encouraging the development of local gas infrastructure and providing the framework of a more favourable gas pricing policy:

- The *Gas Infrastructure Blueprint*, providing for a country coverage by gas infrastructure consisting of 3 gathering pipeline networks to supply 3 central gas processing facilities and 3 gas transmission networks to supply the domestic, regional and export gas markets. Selection of private investors for such projects started in 2009 and is in progress.
- The *Domestic Gas Supply Obligation (DGSO) Regulation,* imposing to producers the obligation of gas reserves allocation for domestic uses, as a condition for authorizing new gas export projects.

- The *Gas Pricing Policy*, dealing with different pricing systems for the domestic sector, the industrial sector (such as fertilizers, methanol, GTL, etc.) and the commercial sector (such as cement plants, steel factories, etc.).

At the end of 2011, the NGMP is only partially implemented.

Gas exports from Nigeria are currently generated an LNG project and a regional gas export pipeline:

- The large NLNG plant built from 1995 to 2007 at Bonny Island by the NLNG Company incorporated in 1999 and owned by the following shareholders: NNPC (49%), the NOC, Shell Gas BV (25.6%), Total LNG Nigeria (15%) and ENI Int. (10.4%). The plant has a current capacity of 23.5 MMtpa with 6 trains on operations, the first one in 1999, requiring 3.5 Bcfd of feed gas at full capacity. Long term *Gas Supply Agreements* (GSAs) for the feed gas required by the plant were signed with 3 joint ventures controlled by the shareholders. A total of 16 long term LNG Sales and Purchase Agreements (SPAs) on a "delivered ex-ship" (DES) basis were signed with buyers. In addition, 42 *Master Spot LNG Sales and Purchase Agreements* (either on a DES or FOB basis) were signed. Additional trains are under study by NLNG. Moreover, two other LNG plants are under study in Nigeria.
- The NLNG company also built a LPG and condensate plant, primarily for exports, with a portion sold on the domestic market.
- The West Africa Gas Pipeline (WAGP) to Benin, Togo and Ghana, on stream since 2009, after many years of delay. The shipped gas is expected to rise gradually to 5 Bcm/year in the next few years.
- In addition, a possible 4,200-km export pipeline through Niger and Algeria to the Mediterranean to supply European markets has been under study, *The Trans-Sahara Gas Pipeline project.* No decision is yet planned in the near future for this costly project.

Today, and in accordance with the agreed NGMP, the priority is given to using more gas in Nigeria in particular for power generation in a country suffering from heavy electricity outages.

8.6 Appendix 6 – Illustrative case countries on specific gas clauses in oil and gas laws

8.6.1 Country Case of 2004 Angola Petroleum Activities Law

This example concerns one of the rare countries which for the time being have not yet decided to encourage the upstream private sector to focus on gas monetization projects in the country–excluding an LNG project under construction.

The provisions of this law apply to both oil and gas, to the exception of two articles over 93 articles: In Article 63.1 where the time period for submission of a development plan is slightly longer for a gas discovery than for an oil field, and in Article 73 which deals with specific provisions for gas in particular regarding associated gas, flaring, joint development as follows:

> *"1. The natural gas produced from any petroleum deposit shall be exploited, and flaring of the same is expressly forbidden, except flaring for short periods of time when required for purpose of testing or other operating reasons.*
> *2. The development plans for Petroleum deposits shall always be devised in such a way as to allow for the use, preservation or commercial exploitation of associated gas.*
> *3. In the case of marginal or small deposits, the supervising Ministry may authorize the flaring of associated gas in order to make its exploitation viable.*
> *4. The authorization referred to in the preceding paragraph may only be granted on submission of a duly substantiated technical and economic and environmental impact evaluation report evidencing that it is not feasible to exploit or preserve the natural gas.*
> *5. The provisions of Article 64 relating to unitization and joint development shall apply, duly adapted, to the exploitation of natural gas.*
> *6. When gas flaring is authorized, the supervising Ministry may determine that a relevant fee be charged in accordance with the quantity and quality of the gas flared and with its location."*

The 2004 Angolan Petroleum Activities Law is illustrative of the scope of a recent oil and gas law dealing with ***petroleum*** **defined as** including altogether "***crude oil, natural gas and all other hydrocarbon substances*** *that may be found in and extracted from, or otherwise obtained and secured from the area of a petroleum concession.*" The object of the law is stated in its Article 1 which excludes explicitly the downstream activities from the scope of the law:

> "*This law seeks to establish the rules of access to and the exercise of petroleum operations in the available areas of the surface and subsurface areas of the Angolan national territory, inland waters, territorial waters, exclusive economic zone and the continental shelf.*
>
> *Other petroleum activities, including the refining of crude oil and the storage, transportation, distribution and marketing of petroleum shall be regulated by separate law.*"

The petroleum agreement entered into under the law contains specific provisions on gas as illustrated in Section 8 which for the time being in reason of the current country gas policy, limit the right of the contract-holder in case of a non-associated gas discovery.

8.6.2 Country Case of the Vietnam Petroleum Law amended in 2000

The 1993 Petroleum Law deals with oil and gas. It was amended in 2000 to introduce more favourable provisions for gas relative to oil in terms of extended duration, tax reduction along with the right to negotiate specific gas development and exploitation agreements.

Under this law, the standard term of a petroleum contract will not exceed 25 years, of which the exploration period will not exceed five (5) years. In the event of gas, Article 17 as amended provides for longer terms, respectively 30 and 7 years. A retention period of up to 7 years may be added to the duration of the petroleum agreement, in order to find and assess the gas markets:

> "*If discovering gas with commercial value, while lacking the consumption market as well as conditions on pipelines and suitable treatment facilities, contractors may retain the areas where gas is found. The duration of retention of such an area shall not exceed five (5) years and may, in special cases, be extended for two (2) more years. Pending the consumption market and the conditions on pipelines and suitable treatment facilities, the contractors shall have to proceed with the work already committed in the petroleum contracts.*"

Under amended Article 30.9 the petroleum contract-holder may have under negotiated gas development agreements specific obligations for selling the gas relative to oil:

> "*To sell on the Vietnamese market a portion of crude oil under its ownership at the international competitive price at the Vietnamese Government's request and sell natural gas on the basis of agreements in gas development and exploitation projects.*"

Article 32 as amended provides that the applicable royalty rate will be fixed in the petroleum agreements within a more attractive range for gas: between 0 and 10% instead of 4 to 25 % for oil.

8.6.3 Country Case of Indonesia

Indonesia corresponds to the case of an oil producing country holding a declining oil production which successfully decided since the 1980s to encourage natural gas exploration and utilization in the country and for exports.

The new Oil and Gas of 2001 which as referred above in Section 7.1 covers both upstream and downstream activities emphasises such pro-active gas policy. As a result of the growing domestic gas uses, the new law highlights in Article 8 (1) the priority to be given to domestic gas uses versus gas exports:

> ***Article 8***
> *(1)* ***The Government shall give priority to the utilization of Natural Gas for domestic needs*** *and has a duty to provide a strategic reserve of Crude Oil to support the supply of the domestic Petroleum Fuel that shall be further regulated by Government Regulation.*
> *….*
> *(3) The business of Natural Gas Transportation by pipeline that concerns public interests, shall be regulated to allow that it utilization is open for all users.*
> *(4) The Government shall be responsible for regulating and supervising business activities as referred to in … and paragraph (3), the implementation thereof shall be conducted by the Regulatory Body.* (Emphasis added]

The law of 2001 also provides that the ***domestic market supply obligation*** (DMO) obligation to be now inserted in any new upstream agreements applies both to oil and gas and not only to oil, as it was the case prior to the promulgation of the new law. Today, the domestic gas uses, which are rapidly growing, corresponds already to over half of the gas production, which requires the fostering of gas exploration to cover both domestic gas uses and exports contracts.

8.6.4 Country Case of Australia

A reference to Australia is made because this country was one of the first to introduce the concept of a ***retention lease*** for allowing the exploration permit-holder of an oil or gas discovery to benefit in specific cases of a longer exploration and appraisal phase for discoveries. This retention concept is now customary under most recent petroleum legislation and regulation although often restricted to gas discoveries. This measure appears as a key driver for encouraging gas exploration and identification of commercial gas markets by granting to the exploration title-holder sufficient time to assess the viability of the discovery and looking for gas markets.

The federal *Offshore Petroleum Act of 2006* as amended provides for the following main licences in upstream activities: an exploration permit, a retention lease, a production licence, an infrastructure licence, a pipeline licence, an access authority. Petroleum covers oil and gas, meaning:

> " *(a) any naturally occurring hydrocarbon, whether in a gaseous, liquid or solid state; or (b) any naturally occurring mixture of hydrocarbons, whether in a gaseous, liquid or solid state; or (c) any naturally occurring mixture of: (i) one or more hydrocarbons, whether in a gaseous, liquid or solid state; and (ii) one or more of the following, that is to say, hydrogen sulphide, nitrogen, helium and carbon dioxide…"*

The Act said in summary that a *retention lease* authorises the lessee to explore for petroleum in the lease area. A retention lease over a block may be granted to: (a) the holder of an exploration permit over the block; or (b) the holder of a life-of-field production licence over the block.

The criteria for granting a retention lease over a block are: (a) the block contains petroleum; and (b) *the recovery of petroleum* ***is not currently commercially viable, but is likely to become commercially viable within 15 years***. The main objective is to evaluate the commercial viability of a petroleum development and is fully appropriate for gas development projects. The retention lease is initially granted **for 5 years** subject to an application containing details on: (a) the applicant's proposals for work and expenditure in relation to the area comprised in the block or blocks specified in the application; (b) the current commercial viability of the recovery of petroleum from that area; and (c) the possible future commercial viability of the recovery of petroleum from that area. A retention lease may be renewed for a period of 5 years each time when the conditions for obtaining a retention lease are met.

The federal government has published *Guideline for Grant and Administration of Retention Lease*. The concept of "*likely to become commercially viable*" is interpreted as follows:

> "…*likely* should be interpreted to convey the sense of a "substantial or real chance as distinct from what is a mere possibility"; *commercially viable* petroleum should be interpreted to mean that the petroleum could be developed (a) Given existing knowledge of the field, (b) Having regard to prevailing market conditions, and (c) Using proven technology readily available within the industry, such that the commercial rates of return from recovery of the petroleum (including recovery of all operating and capital costs and taxes, royalties and other charges) meet or exceed the minimum return considered acceptable for the type of project under consideration by a reasonable petroleum

developer and by investors or lenders to the industry (i.e. an acceptable rate of return). Existing knowledge of the field includes mapping and resource estimates at proved, probable and possible probability levels. …"

The possibility of ***joint gas development projects*** combining the resources and infrastructure with third parties is encouraged under the Guideline:

> "Where commercial viability is dependent on combining a development with other potential third party developments or access to third party facilities or technology, the petroleum will not be considered commercially viable if the titleholder is unable to complete an agreement **to jointly develop or complete an access agreement** for use of facilities or technology which provides an acceptable rate of return. …The Joint Authority may declare an offshore pipeline to be subject to common carriage. [Emphasis added]

The specific constraints for gas concerning: (1) the extra time required for negotiating long term supply contracts, a pre-requisite for monetizing gas, and (2) the need of discovering a minimum threshold of gas reserves for signing such contacts, are also taken into account in the Australian Guideline which details the ways for justifying economic viability:

> **"In addressing market issues**, including market access, prices, and timing of market opportunities, it will be accepted that a potential market exists for crude oil, condensate or LPG recoverable from a project and that the terms and conditions of supply will determine the viability of the project. ***However, it is recognised that the market for natural gas is often characterised by large, long term contracts****,* at specified rates over specified periods, and specific quality. Therefore in some circumstances, the Joint Authority may agree that an otherwise commercially viable gas project (assuming current prices) is not commercially viable and may not proceed due to an inability to obtain a contract at prevailing market terms and conditions, which would support development. Alternatively the Joint Authority may accept that the level of resources, while substantial may be insufficient to meet any currently available market opportunity (e.g. an LNG project)."[Emphasis added]
>
> In recognition that market considerations can stall an otherwise commercially viable 'dry' gas project, the Joint Authority will give favourable consideration to an application for a lease if the applicant has demonstrated reasonable attempts in good faith to obtain gas supply contracts which were unsuccessful. In such a case, the major test in assessing whether the criteria have been met is likely to be assessing the applicant's efforts in obtaining a market for gas if the project can be demonstrated to be viable at prevailing prices (i.e. otherwise passes the commerciality test). However in order to enhance the marketability of a project, it might be reasonable to expect that the lessee better define the resource if this would be necessary to demonstrate supply capability to potential buyers.
>
> An application should include an analysis of the commercial viability of a prospective development including the assumptions, the methodology, and the conclusions reached by the applicant. This analysis should provide sufficient information to demonstrate that the assumptions and methodology are realistic and lead to a likely outcome (and if appropriate, a range of outcomes). The impact of alternative reasonable assumptions should also be identified and assessed. Government will analyse the extent to which there are reasonable grounds for adopting alternative assumptions and methodologies…"

8.7 Appendix 7 – Selected case countries on gas provisions in oil and gas upstream contracts

8.7.1 The case of Vietnam PSCs

Vietnam is the example of a country holding substantial potential gas resources which decided to promote the exploration and monetization of such resources. This policy is reflected under the legal framework and the terms of the 2007 model production sharing contract. The PSC contains many clauses regarding gas, including the following provisions:

- In case of a commercial gas discovery the following Article states the obligation for the contractor to develop it as soon as practicable when the markets exist:

  Art. 6.2.5 When a Commercial Discovery of Natural Gas has been made in the Contract Area, CONTRACTOR shall commit to develop such Commercial Discovery without delay subject to the availability of a market on terms that in the sole opinion of CONTRACTOR are acceptable.

- The priority in the different uses of gas by the contractor and the procedure for identifying gas markets up to the signing of gas sales agreements (defined herein as "gas offtake agreements"):

  Art. 6.2.6 CONTRACTOR may freely utilize Natural Gas, at no Royalty burdens, for the conduct of Petroleum Operations in accordance with Generally Accepted International Petroleum Industry Practices including but not limited:

  (a) to use in production, process and associated facilities and utilities;

  b) to facilitate or enhance Crude Oil production;

  (c) to effect pressure maintenance by secondary or tertiary recovery processes;

  (d) to process so as to extract Crude Oil;

  (e) to recycle;

  (f) to utilize Natural Gas for well maintenance or appraisal or to enable production of Crude Oil; or

  to flare , in the absence of other economical solutions or in the case of emergency, subject to approval of the State Petroleum Management Authority.

  Art. 6.2.7 In the event that a significant quantity of Natural Gas has been determined by CONTRACTOR to exist in the Contract Area, CONTRACTOR shall promptly inform PETROVIETNAM of such Discovery and shall undertake an evaluation of the commerciality thereof. CONTRACTOR shall notify PETROVIETNAM of the results of the said evaluation. If the evaluation indicates that the quantities of Natural Gas discovered are capable in principle, in CONTRACTOR's sole opinion, of being developed commercially, the Parties shall use their best efforts to find gas market and CONTRACTOR and PETROVIETNAM (or a third party as may be agreed by the Parties) shall enter into a binding Gas Offtake Agreement for the purchase of gas based on a duration and minimum quantity to be agreed by the Parties. CONTRACTOR shall proceed to appraisal and development of the subject Discovery so as to meet the demand of the Gas Offtake Agreement.

- The right to obtain the so-called "gas retention period" for assessing the viability of a discovery, which is referred under the PSC model as a "suspended development area":

Art. 6.2.8 Should CONTRACTOR consider a Discovery of non-associated Natural Gas not to be potentially commercially viable so as to warrant appraisal at the time the Discovery is made by CONTRACTOR, but such Discovery is, as a result of the studies conducted thereon likely to become commercially viable by reason in particular of potentially extra revenues or a potential improvement in the market for Natural Gas or of Petroleum development and production techniques or of new gas utilization technologies, that part of the Contract Area encompassing the Discovery shall, for the purposes of this Contract, be designated as a Suspended Development Area. In this case CONTRACTOR may retain such area subject to the Prime Minister's approval.

- In case of gas production, different fiscal terms apply to gas versus oil. Thus the gas royalty rate is lower, ranging per increment of production from 0% to 6% for the so-called "investment incentive projects", and from 0% to 10% for other gas projects. In a similar way the cost recovery gas limit and the profit gas sharing may be more favourable to the PSC-holder.

- Moreover, a specific short gas pricing provision is stated, quite different from the 2-page oil valuation clause as marketing conditions for oil are not fully relevant to gas:

Art. 8.1.5 Natural Gas shall be sold at agreed price in accordance with producing principles applicable to Natural Gas sales prevailing international market at the time of calculation, taking into account market location, quality, quantity and other relevant factors.

8.7.2 The case of Timor Leste PSCs

The 2006 model PSC contains modern provisions related to gas designed to foster investments. They consist in particular with the grant in case of a non-associated gas discovery of a 5-year retention period covering a "gas retention area" for evaluating the commerciality of the discovery, either alone or jointly with other discoveries, the procedure for approval of gas contracts, the no-flaring obligation and gas valuation, as displayed below. The fiscal regime applicable to the company and the production sharing terms remain identical both for oil and gas as a result of the introduction of a supplementary profits tax assessed on an effective profitability criterion.

"Art. 3 Gas Retention Area
(a) If the Appraisal of a Discovery of Non-Associated Gas demonstrates that the Discovery, although substantial, is not then, either alone or in combination with other Discoveries, commercially viable, but is likely to become so within five (5) years, the Ministry may, at the request of the Contractors, declare a Gas Retention Area in respect of it for that period.

(b) This Article 3 (but not Section 3.3) applies to and in respect of a Gas Retention Area as it does to and in respect of a Development Area for as long as, during that period, the Contractors diligently seek to make it commercially viable, and demonstrate to the Ministry that they are doing so.

(c) The Gas Retention Area consists of a single contiguous area that encompasses the Gas Field, plus a reserve margin sufficient to cover the probable and possible extent of it, but the Ministry may exclude deeper formations in which no Discovery has been made. The Ministry, at any time and from time to time, and whether of its own volition or at the request of the Contractors, may:
(i) increase;
(ii) decrease; or
(iii) vary the depth within the Contract Area of;

a Gas Retention Area as may be required to ensure that it encompasses the Gas Field. The Contractors shall relinquish any part of the Contract Area removed from a Gas Retention Area as a consequence of such decrease or other variation if it occurs after the time for the relinquishment provided for in paragraph 3.2(a).

(d) The Gas Retention Area shall be deemed to have been relinquished on the earlier of:
(i) expiry of the period mentioned in paragraph 3.5(a);
(ii) the Contractors ceasing to meet their obligations under paragraph 3.5 (b); and
(iii) the Contractors declaring a Commercial Discovery in respect of it and the Ministry declaring a Development Area as a consequence thereof.

In 4.11 d) of Art. 4 Development Plan
…
(xi) summary details and copies of:
(aa) all contracts and arrangements made or to be made by each Contractor for the sale of Natural Gas;
(bb) all contracts and arrangements made or to be made by persons in respect of that Natural Gas downstream of the point at which it is to be sold by the Contractors and which are relevant to the price at which (and other terms on which) it is to be sold by the Contractors or are otherwise relevant to the determination of the value of it for the purposes of this Agreement, but not beyond the point at which it is first disposed of in an arm's length transaction; and
(cc) all contracts and arrangements made or to be made by the Contractors in respect of facilities downstream of the Field Export Point for transporting, processing, liquefying, storing, handling and delivering that Natural Gas; …

Art. 4.13 Approved Contracts
(a) The Contractors may not sell or otherwise dispose of Natural Gas from the Contract Area other than pursuant to an Approved Contract or as otherwise may be provided in the Development Plan or in this Agreement.

Art 5.5 Flaring
Except with the consent of the Ministry, or in an emergency, the Contractors shall not flare Natural Gas.

Art 10.3 Value of Natural Gas
The value of Natural Gas is the price payable under Approved Contracts or as otherwise may be provided in the Development Plan or in this Agreement, with such fair and reasonable adjustments as required to reflect the point of valuation in Section 10.1.

Art. 10.4 Price Payable
In this Article 10, the price payable is the price that is (or would be) payable by the buyer if the Petroleum were delivered by the Contractors and taken by the buyer, without set off, counterclaim or other withholding of any nature."

8.7.3 The case of Angola PSCs

This example illustrates a situation where the contract basically grants to the contractor rights to oil and to the portion of the associated gas required for its own operations, the balance of produced gas being available to the NOC at cost.

In case of a non-associated gas discovery, the rights for its appraisal and exploitation are automatically vested in the Angolan NOC without any compensation to the contractor, except if the NOC invites the contractor to participate in the development of the gas field on terms to be agreed upon, as stated below in Article 29 of the model PSC:

"*Article 29 Natural Gas*
1. Contractor Group shall have the right to use in the Petroleum Operations, Associated Natural Gas produced from the Development Areas.

2. Associated Natural Gas surplus to the requirements defined in the preceding paragraph shall be made available free to Sonangol, wherever the latter so determines. The cost of transportation of said gas by pipeline is a recoverable cost under the Law.

3. If Non-Associated Natural Gas is discovered within the Contract Area then Sonangol will have the exclusive right to appraise, develop and produce the said Gas on its own account and risk.

If Sonangol so determines and if agreed with Contractor Group within a term determined by Sonangol, the discovery of Non-Associated Natural Gas shall be developed jointly by Sonangol or one of its Affiliates and Contractor Group."

Such principle providing in the Angolan PSC the automatic transfer of a gas discovery to the State or its NOC was customary in many countries several decades ago, prior to the introduction by Egypt in the 1980s of the so-called *gas clause.*

Now, such transfer to the State remains quite exceptional as the majority of developing countries desire on the contrary to foster investments in gas development projects by granting to the PSC-holder the same exploitation rights whatever the nature of the discovery, oil or gas, and often offering more attractive fiscal and contractual terms for gas projects.

8.7.4 The example of the Indian CBM PSC

The example of India concerning CBM activities illustrates the case of application to CBM activities of the existing legal, regulatory and contractual framework initially designed for oil and natural gas, subject only to some adjustments for CBM.

Thus, the model CBM production sharing contract remains similar to the petroleum PSC, but adapted to take into account the CBM specificities. As stated in the CBM PSC's preamble, the reason for such approach is that: "*The Coal/Lignite Bed Methane (CBM) is a **Natural Gas**, and, therefore, it is governed by [the Oilfields (Regulation and Development)] Act and the [Petroleum and Natural Gas] Rules."*

Under the Indian CBM PSC, the concepts of natural gas, petroleum operations, field, development plant, wells, delivery points, site restoration and good oil field practices were adjusted in the following way, with the introduction of the specific concepts of *Pilot Assessment Operations* and *Commercial Assessment,* such a pilot being required to demonstrate the commercial viability of a CBM development project prior to its approval by the State. The traditional reference to good oil field practices became under the CBM agreement a reference to "*CBM/oilfields and petroleum industry practices":*

" "Natural Gas" means gas obtained from Wells and consisting primarily of hydrocarbons and includes CBM but does not include helium occurring in association with such hydrocarbons.

"CBM Operations" means, as the context may require, Exploration Operations, Development Operations or Production Operations or any combination of two or more such operations including, but not limited to, construction, operation and maintenance of all necessary facilities, plugging and abandonment of Wells, environmental protection, transportation, storage, sale or disposition of CBM to the Delivery Point, Site Restoration and all other incidental operations or activities as may be necessary.

“CBM Field” means an area within the Contract Area consisting of a single CBM Reservoir or multiple CBM Reservoirs all grouped on or related to the same individual geological structure or stratigraphic conditions, (to include the maximum area of potential productivity in the Contract Area) in respect of which a Potential Commercial Assessment has been declared, Commercial Assessment has been made and a Development Plan has been approved in accordance with Article 5.

“Field” means CBM Field in respect of which a Development Plan has been duly approved.

“Pilot Assessment Operations” mean operations conducted in the Contract Area pursuant to this Contract for the purpose of assessment of CBM potential.”

8.8 Appendix 8 – Overview on other types of upstream gas agreements

The following highlights the main characteristics of contracts other than the upstream agreements signed with the State, which are specifically used in the gas industry:

- *Gas sales and purchase agreements* signed between the gas producers and the buyers of the gas;
- *Gas balancing* agreements for allocating under lifted gas between the producers*;*
- *Gas transportation agreements* dealing with pipelines*.*

8.8.1 Gas sales and purchase agreements (GSAs)

8.8.1.1 Overview of gas sales agreements and main types of GSAs

Gas sales agreement (GSAs), often classified as *gas sales and purchase agreements* (GSPAs), provide for the long-term sale by the seller to a buyer of certain quantities of natural gas, delivered at a given point of the gas supply chain. Such contracts often last between 15 to 25 years, especially when they are related to the sale of LNG or exports of pipeline gas using a specially built pipeline. In some case shorter term agreements or spot sales may be negotiated.

Two main categories of GSAs exist depending on the dedication or not for the purposes of the agreement of the future production, in all or in part, coming from identified gas reservoirs or fields, namely:

- GSAs designed on the supply by the seller of dedicated reserves, to be produced from identified gas/oil reservoirs or fields and supplied at the delivery point, corresponding in short to "*dedicated GSAs*". In this case, the agreement provides for a detailed mechanism in order to adjust the daily and annual quantities to be supplied and purchased in relation with the dedicated gas reserves, as they are periodically re-estimated under the procedure provided for in the agreement.

- *Pure supply agreements* under which the seller may freely select the source of the gas to be supplied at the delivery point to the buyer. Thus, the daily and quantities of gas to be supplied and purchased remain equal to the quantities stipulated in the initial agreement without any adjustment on reserves.

Dedicated supply agreements mainly concern new gas projects in new producing zones–for example the North Sea in the 1980s–and in developing countries for new projects when the investor desires obtaining project financing for monetizing the discovered gas resources.

GSAs of each category include always provisions on contractual quantities along with a "**take-or-pay**" (TOP) obligation for the buyer to accept on an annual basis the minimum quantities specified under the agreement–often equal to 80% of the annual contract quantities–otherwise it will compensate the seller by paying the seller for the gas not taken with the "*TOP payment*", except if the under lifting results from a force majeure event as defined in the agreement. Some limited flexibility clauses on daily and annual quantities to be taken exist in the agreement.

Another key clause in any supply agreements deals with the detailed procedure to be followed for gas price determination at any time during the validity of the agreement. The resulting gas price at the delivery point when the sale meets the “arms length conditions criteria” constitutes the basis for fiscal purposes under the upstream agreement when applicable.

Many models of GSAs exist in the world depending on the category of agreements and the types of gas markets. The Association of International Petroleum Negotiators (AIPN) published in 2006 a *Model Form for Gas Sales Agreement* along with *Guidance Notes* which provide alternatives to GSA’s drafters appropriate to long term gas supplies projects from countries with emerging gas supply/demand markets. The model form contemplates alternatives for dedication of reserves and project financing.

8.8.1.2 Main clauses under a GSA

In short, a GSA contains near 30 clauses dealing with legal, contractual, operational, economic and fiscal matters. For illustration purposes, two clauses are only summarized below.

When dealing with dedicated GSAs, the committed gas quantities and the related TOP are directly adjusted in relation with the most recent estimate of *Economically Recoverable Reserves* (ERR) regarding the allocated reservoirs and fields as defined in the agreement. A *reserves report* stating the quantities of gas projected to be produced and the ERR is prepared periodically by the seller to set out the seller’s estimate of the remaining ERR. Such estimate may be objected by the buyer and in case of dispute the matter is generally settled by an independent expert selected by the parties.

The contract gas price typically consists of:

- A *base price* periodically adjusted on the variations during the relevant period of *several indices*, each one holding a specific percentage weight in the price adjustment formula.
- *An indexed floor gas price and ceiling gas price* to limit the possible range of gas price variations for a given period, in order to respectively protect the seller for its investment in the upstream project, and the buyer by preventing a situation where the purchased gas under the TOP obligation would become non competitive with alternative energy sources or feedstock.
- A price *reopener clause*, or an *hardship provision*, to renegotiate the gas price determination clause in case of major gas markets structural changes.

GSAs may use a combination of several indices among a long list of possible indices relevant to gas markets, such as:

- Oil products prices indices, using for example quoted heating oil and/or heavy fuel oil prices on a given trading hub when such products are competing with gas;
- Crude oil prices indices, often based on a basket of several quoted oil prices, assuming that the evolution of crude oil prices will remain in line with oil products markets prices;
- Coal indices, to reflect the evolution of coal prices when competing with gas for power generation;

- Electricity indices, to reflect the role of electricity as a competitor to gas for some end-users;
- Natural gas prices indices, such as the spot gas prices on some gas trading hubs or other published gas prices;
- Inflation indices.

8.8.2 Gas balancing agreements (GBAs)

This category of agreements provides for how the gas production will be allocated between the several holders of an upstream petroleum agreement and how any gas production imbalance will be settled between the holders when joint selling of gas by such holders is not possible or desirable for legal or commercial reasons.

GBAs indeed complement the *joint operating agreement* (JOA) entered into between the various co-venturers in relation with an upstream agreement. Moreover, they take into account the specific conditions resulting from the selected field development and transportation facilities or the signed GSAs.

8.8.3 Gas transportation agreements (GTAs)

The petroleum law and regulation provide for the legal and fiscal framework covering gas transportation by pipelines from oil and gas fields. Depending on the selected development scheme, pipelines may consist along the gas supply chain of (1) the gathering lines from the wellheads to the main processing plants and (2) then a main pipeline–the so-called "*upstream gas pipeline*"–from such plants to a given point of entry into a trunk line where gas entered the downstream sector. In some cases, such main pipeline is also called "a *downstream gas pipeline*" (or in North America a "*midstream gas pipeline*") governed by the gas law dealing with the downstream activities.

The construction and use of a *pipeline transportation system*–consisting of pipelines, compression stations, metering stations and other facilities–requires the grant of a ***pipeline licence* or a pipeline *concession*** under the applicable legal and regulatory framework. The duration of a pipeline licence or concession often lasts 20 to 25 years and may be renewed. The licence specifies *inter alia* the regime allowing third parties to use an existing pipeline when its capacity is not fully utilized, subject to the payment of a tariff which may be regulated or negotiated. Such right is defined as "third party access" (TPA). Depending on the country legal framework, pipeline transportation may be classified either as a regulated industry, or a non-regulated one in terms of pipeline access and tariffs.

Moreover, when the gas pipeline crosses the border between two or more countries–corresponding to the situation of a "transnational or cross-border pipeline"–the signing of a *bilateral treaty* between the countries is required for the construction and use of such pipeline. They are many examples, such as in the North Sea or between North Africa and Europe.

An upstream petroleum agreement provides that its holder is granted in case of commercial exploitation *the right to build and use* the necessary pipelines to transport its production beyond the "delivery point" as defined in the agreement –which point is generally located at the outlet of the processing facilities dedicated to the fields covered by the upstream agreement–up to the domestic or export markets.

For fiscal reasons and because such main pipeline may also be used by other companies for encouraging economies of scale, the pipeline project itself is generally considered as *a distinct project* from the upstream project, owned and operated by a separate legal entity. Thus, under a PSC the pipeline costs–including investment and operating costs–are not directly recoverable under the contract's cost recovery mechanism. However, the pipeline tariff is deductible from the gas market price get at the outlet of the pipeline to determine on a *net back basis* the gas price at the field gate for all purposes under the PSC. The legal, regulatory and fiscal regime applicable to the pipeline is governed by the pipeline licence or concession granted by the competent authority of the country.

Long-term gas transportation agreements (GTAs) are therefore entered into between the company owning the pipeline (called "the transporter") and each of the users of the pipeline ("the shippers"), the shareholders of the pipeline company and/or third parties. The terms and conditions of GTAs vary from one pipeline transportation system to another, taking into account the specific context and regulatory framework. The main clauses under a GTA are the following:

- the contractual gas quantities and qualities to be transported;
- the annual capacity reservation;
- the determination of the tariffs;
- the *"**ship or pay**" payment* clause related to the annual reserved capacity if the shipper does not fully use such capacity during a year.

The main objective of any pipeline tariff formula is allowing the pipeline company to recover its investment and other costs, including a *fair and reasonable return* on its equity or investment base. The tariff formula is generally composed of two components, each one periodically adjusted on a series of indices:

- The first component is based on the capacity reservation made by the shipper;
- The second one is related to the effective quantities transported for the shipper.

For reference purposes, two *Model Forms for Gas Transportation Agreement* which provide for various drafting options were published in 2009 by AIPN along with *Guidance Notes*.

8.9 Appendix 9 – Illustrative case countries on the scope of gas laws

8.9.1 Evolution of gas laws in the US and Canada

The first gas law promulgated in the US was the *Natural Gas Act* (NGA) *of 1938*, periodically amended or supplemented, in particular by the Natural *Gas Policy Act* (NGPA) *of 1978*, the *Natural Gas Wellhead Decontrol Act* (NGWDA) *of 1989* and the many orders issued by the *Federal Energy Regulatory Commission* (FERC), the competent federal authority for the sector. The US gas regulatory framework went through different phases and continues to evolve. While the gas price was controlled up to 1978, this is no more the case as there is a move towards more deregulation. *FERC Order N° 636 of 1992* provided for obligatory *unbundling* of gas transmission services, separating pipeline transportation services from supply, sales and marketing of gas to consumers. Regulated pipeline tariffs and third-party open access on a non-discriminatory basis for onshore and offshore gas pipelines apply to foster the development of gas markets and marketing of gas by third parties.

Similarities can be found between the US and Canada in their gas regulatory frameworks, such as the role of a regulator, the US FERC or the Canadian National Energy Board (NEB), the respective allocations of regulatory powers between the federal state and the local states (or provinces), in particular between the Public Utility Commissions (PUCs) in the US and the provincial Energy Utility Boards (EUBs) in Canada, the regimes of *intrastate pipelines* (within state or provinces territories) and *interstate* (or interprovincial) *pipelines*.

In both countries, gas exports or imports are subject to obtaining a prior *gas export or import licence* following an open hearing process. Section 3 of the US Natural Gas Act sets forth the criteria for review of the export or import application, providing that: "*No person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest*." The *Guidelines* issued further to the act provide that "*the market, not government, should determine the price and other contract terms of imported [or exported] natural gas. The federal government's primary responsibility in authorizing imports [or exports] will be to evaluate the need for the gas and whether the import [or export] arrangement will provide the gas on a competitively priced basis for the duration of the contract while minimizing regulatory impediments to a freely operating market*." As an example, the exports of LNG from Alaska to Japan were authorized under such an export licence process.

8.9.2 The successive UK Gas Acts

The UK enacted several gas laws, namely: the *Gas Acts of 1948, 1965, 1972, 1986 and 1995*, such laws being supplemented *inter alia* by the *Energy Act of 2008* and the UK and European Union competition legislation. This succession of gas laws illustrates the evolution of the UK downstream gas policies from the 1948 gas nationalization towards the 1986 and 1995 gas activities' privatization designed to create a more open and competitive sector while protecting the customers.

The gas acts deal with the organization of the downstream gas sector, the regulatory framework for onshore processing, transmission and distribution networks, storage, LNG terminals, supply and distribution up to the gas end-users, tariffs and gas pricing. *The Office of The Gas and Electricity* Markets (*Ofgem*) is the regulator for the UK's gas and electricity industries. Its role is to protect the consumers "*by promoting competition where possible, and through regulation only when necessary*." A *licensing system* applies for authorizing transportation, shipping and supply activities.

In addition, *the Petroleum Act of 1998* dealing with upstream gas activities contains in its Section 17B additional provisions relating to "offshore downstream gas pipelines" aimed to encourage third-party access rights to such pipelines. Thus, "*The owner of a downstream gas pipeline to which this section applies (a " relevant downstream gas pipeline") …shall publish at least once in every year the main commercial conditions relating to the grant to another person of a right to have gas conveyed in the pipeline on that person's behalf."*

The Gas Act of 1986 provides the key objectives of the current UK gas policy by stating that:

> *"…the Secretary of State and the Director [of Ofgem] shall each have a duty to exercise the functions assigned to him….:*
>
> *(a) <u>to protect the interests of consumers</u> of gas supplied through pipes in respect of the prices charged and the other terms of supply, the continuity of supply and the quality of the gas supply services provided;*
>
> *(b) <u>to promote efficiency and economy</u> on the part of persons authorised by or under this Part to supply gas through pipes and the efficient use of gas supplied through pipes;*
>
> *(c) to protect the public from dangers arising from the transmission or distribution of gas through pipes or from the use of gas supplied through pipes;*
>
> *(d) <u>to enable persons to compete effectively</u> in the supply of gas through pipes …"[(emphasis added]*

8.9.3 The first gas law in Cameroon: The 2002 Cameroon Gas Law

The following excerpts from the Cameroon Gas Code are illustrative of the objectives and content of a recent gas law in a developing country. The scope of the law only concerns downstream activities with the objective of gas promotion and fostering gas projects:

> *"Section 1: This law…..shall govern the downstream gas sector comprising transportation, distribution, processing, storage, importation, exportation and marketing of natural gas within the national territory.*
>
> *Except otherwise provided, this law shall exclude the following:*
>
> *- prospecting, exploration, exploitation, transportation, storage and processing activities of liquid or gaseous hydrocarbons as governed by Law n° 99/13 of 22 December 1999 to institute the Petroleum Code ;…*
>
> *Section 2: The purport of this law is to promote the development of the downstream gas sector in Cameroon. As such, it is aimed at:*
>
> *- putting in place a legal framework conducive to the development of gas resources;*
>
> *- setting up an attractive environment for private national and foreign investors in the gas sector;*
>
> *- laying down principles governing regulation of the sector;*

- guaranteeing the safety of facilities and environmental protection."

The downstream gas sector is regulated by the minister responsible for petroleum with the possibility in the future to establish an agency:

> *"Section 5: The activities referred to in Section 1 above shall fall under the authority of the Minister in charge of hydrocarbons or any public establishment entrusted with the regulation thereof.*
>
> *Section 6: (1) The regulation of the downstream gas sector shall, in particular concern:*
>
> *- control and monitoring of the activities of exploiters and operators of the downstream gas sector ;*
>
> *- promotion and rational development of gas supply;*
>
> *- economic and financial balance of gas sector as well as preserving economic conditions necessary for its development;*
>
> *- protection of the rights and interests of the consumer, in particular as concerns price, supply and gas quality;*
>
> *- promotion of competition and private sector participation in the secondary gas sector;*
>
> *- implementation, monitoring and control of the tariff system, as well as ensuring respect of the modalities and procedures in force;*
>
> *- overseeing the implementation of the technical regulations on hygiene, safety and the laws and regulations in force governing environmental protection;*
>
> *- implementation and monitoring of the application of the rules governing access by third parties to gas transportation and distribution networks;*
>
> *- monitoring the implementation of norms and standards by operators in the downstream gas sector;''*

The gas transmission and distribution activities are under Section 8 of the law subject to the grant of a concession awarded for a renewable period of 25 years on the conditions stated in a *concession contract* defining the rights and obligations of the transporter or distributor*. "The concession shall be valid only within the area for which it is granted."*

On the contrary, under Section 14, the activities for processing–meaning "gas liquefaction, petrochemical and gas-chemical operations"–storage, importation and exportation of gas are governed by licence regulations and subject to the grant of a *licence* which is "*an instrument by which the Minister in charge of hydrocarbons authorizes an operator to exercise, under transparent and non-discriminatory conditions. … However, in respect of processing and storage licences, specifications shall define the conditions for and methods of exercising such activity*." A licence is granted for a renewable period of 15 years for processing and storage activities; and 5 years for gas importation and exportation activities.

The principles for pricing of services and gas are stated as follows, providing for the "cost of services plus a reasonable return on equity" approach:

> *Section 33: The rates applied to final customers shall be fixed on the basis of a method and parameters adopted beforehand by agreement between the competent authority and operators of the sector.*
>
> *Section 34: Gas supply activities shall be remunerated and regulated on the basis of mechanisms which enhance optimum management, profitability of activities as well as product quality improvement.*

Section 35 : (1) Remuneration for the transportation and distribution of gas shall be fixed on the basis of a method and parameters defined by the competent authority in accordance with Section 34 above.

(2) The competent authority shall ensure that rates charged take into account investment, operation and equipment maintenance costs, other costs incurred in the exercise of the activity as well as an equitable reward for the invested capital such as is applied in similar activities and including development costs.

(3) The pricing formula shall include incentives for cost reduction and an improvement of product quality.

(4) Pricing shall be reviewed on a regular basis and applied by the competent authority following a time frame and procedure stipulated in the concession contracts.

Concerning tax issues, activities related to the transportation, distribution and sale of gas are liable to taxes laid down by the *General Tax Code*. The companies engaged in several downstream activities are obliged "*to keep separate accounts for each transportation and/or distribution concession, as well as for any permit or authorization*" which are separately taxable.