



The World Bank Group

THE PETROLEUM SECTOR VALUE CHAIN

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This paper is a working draft of Chapter 1 of the *Study on National Oil Companies and Value Creation* (the “*Study*”). An updated version of this paper will be included in the *Study* launched in March 2008 by the Oil, Gas, and Mining Policy Division of The World Bank, and expected to be completed by June 2010. The manuscript of this paper has not been prepared in accordance with the procedures appropriate to formally edited texts. Some sources cited in this paper may be informal documents that are not readily available.

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Acknowledgments

This *The petroleum sector value chain* is intended as a contribution to the *Study on National Oil Companies and Value Creation* (launched in March 2008) by the Oil, Gas, and Mining Policy Division of The World Bank.

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THE PETROLEUM SECTOR VALUE CHAIN

“The weakest link in a chain is the strongest because it can break it.

(Stanislaw Lec)

1. Introduction

The oil and gas industry encompasses a range of different activities and processes which jointly contribute to the transformation of underlying petroleum resources into useable end-products valued by industrial and private customers. These different activities are inherently linked with each other (conceptually, contractually and/or physically), and these linkages might occur within or across individual firms, and within or across national boundaries.

This chapter will briefly describe the key constituent activities of the petroleum sector. It does so based on the notion of an industry value chain (or value system, as typically more than one firm is involved in the sector). It will also present some of the key policy decisions associated with the different stages of the value chain. Overall, this chapter seeks to introduce key activities, value drivers and risk factors of the petroleum industry.

The focus of the Study is the creation of social value at the country-level rather than private shareholder value. Consequently we examine the industry value chain (national petroleum value system), and consider the contribution of individual firms to social value creation. Although all stages of the industry value chain will be discussed, there is a deliberate emphasis on upstream operations.

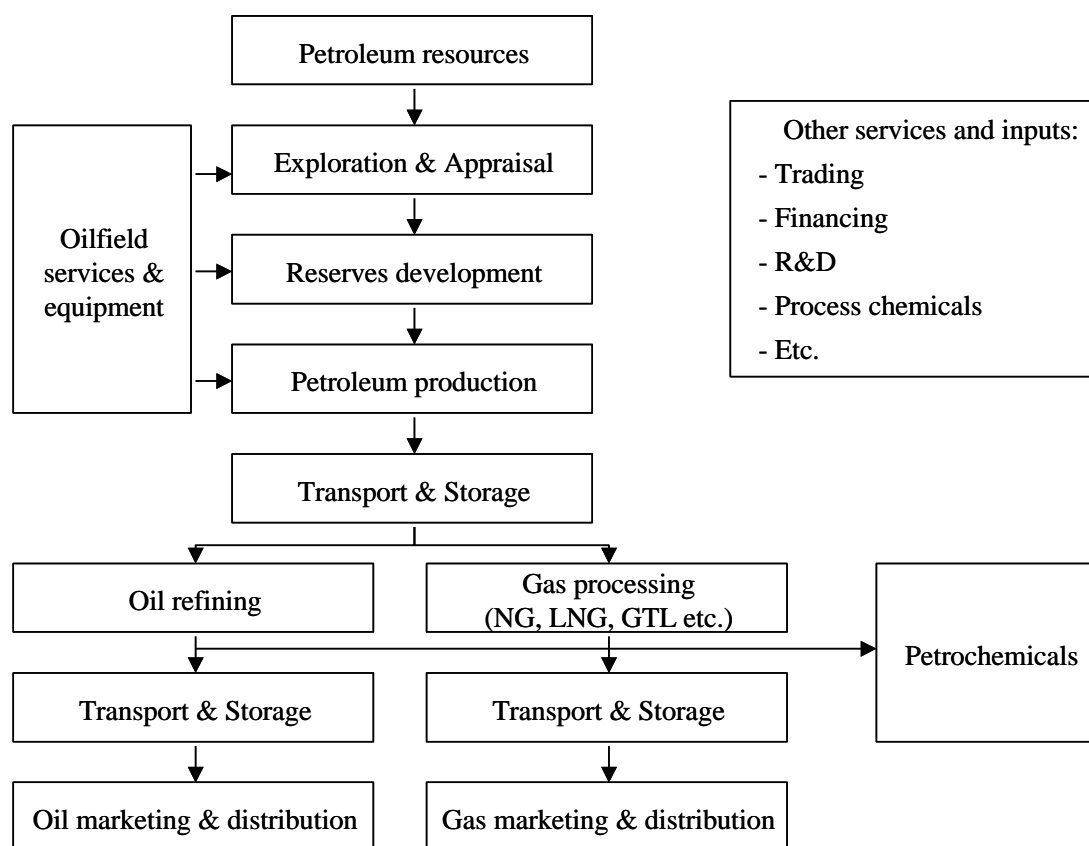
Section 2 describes the petroleum sector value chain and briefly discusses key drivers of value creation in the sector, illustrated by empirical data on exploration and production activities. Section 3 describes the individual stages of the value chain. Section 4 reviews the argument for horizontal concentration and vertical integration in the sector. Section 5 focuses on some key policies that influence value creation through the institutional context. Section 6 concludes.

2 The petroleum sector value chain

For the purpose of this Study, value creation is an aggregate benefit to society, parts of which are captured by different actors.

The value chain analysis, as popularized by Porter (1985), investigates the sequence of consecutive activities which are required to bring a product or service from conception and procurement, through the different phases of production and distribution, to the final customer.¹ Such analysis can be done for individual firms, for clusters of firms whose value chains are interlinked – usually involving suppliers, distributors/sellers and customers, and referred to as value systems by Porter – or for selected industries (within or across national borders). In line with our focus on social value creation, we will consider the industry value chain for the petroleum sector. Its principal stages are the development, production, processing, transportation and marketing of hydrocarbon, as set out in Figure 1.

Figure 1: Petroleum value chain



Source: Author

¹ Porter distinguishes between the different stages of supply, the physical transformation from inputs to outputs, and the critical supply services of the firm such as strategic planning or technology development. Porter argues that the greatest value is frequently added by these latter services, and also by the specific combination in which the individual pieces of the chain are combined: “Although value activities are the building blocks of competitive advantage, the value chain is not a collection of independent activities. Value activities are related by linkages within the value chain” (Porter 1985, p.48).

The value chain starts with the identification of suitable areas to conduct exploration for oil and/or gas.² After initial exploration, petroleum fields are appraised, developed and produced. These activities are generally called Exploration and Production (E&P), or referred to – analogous to other industries – as “upstream” oil and gas. Oilfield services include a number of auxiliary services in the E&P process, such as seismic surveys, well drilling, equipment supply or engineering projects. They form an important part of the overall oil and gas industry (and over the past years and decades have substantially gained in expertise and importance), but will not be the focus of our overview. Infrastructure such as transport (pipelines, access to roads, rail and ports etc.) and storage are critical at various stages in the value chain, including the links between production and processing facilities, and between processing and final customer. These parts of the value chain are usually referred to as “midstream”. Oil refining and gas processing are required to turn the extracted hydrocarbons into usable products. The processed products are then distributed onwards to wholesale, retail or direct industrial clients (Refining and Marketing (R&M) is also referred to as “downstream” oil). Certain oil and gas products represent the principal feedstock for the petrochemicals industry, which explains the close historical and geographical links between the two.

Individual companies can cover one or more activities along the value chain, implying a degree of vertical integration (“integrated” firms are engaged in multiple successive activities, typically E&P as well as R&M), and/or can seek to expand within a given activity, implying horizontal consolidation (business scale). On the country level, horizontal scale in the upstream is limited by natural resource endowments, and further downstream by the size of the domestic market and/or the ability to export goods and services. Vertical portfolio choices at the country level can be made using regulatory and licensing tools, e.g. approval (or not) to build certain processing facilities or infrastructure such as pipelines.

2.1 Value creation

How, then, is value created along the chain? The formal criterion is for the value of aggregate outputs to exceed the value of aggregate inputs on a sustainable basis.³ At the most general level, the potential sources of (contributors to) petroleum sector value creation are:

- (i) *Exogenous context and conditions.* Many variables are exogenous to the actors’ decision-making, but can materially affect value creation. These factors include, amongst others:
 - the quality and quantity of the resource endowment (incl. geological properties), which determines the availability, technical complexity and implied cost structure of upstream production;
 - the geographic position of the country in question (and of the resources within the country), which determines the access to domestic and export markets as well as the availability of natural infrastructure (sea ports, rivers etc);

² The description of the petroleum value chain is very much based on conventional oil – alternative sources such as oil sands or shale oil require different extraction processes.

³ By “aggregate inputs” we mean all economic costs such as production cost, cost of funding, cost of resource depletion (Heal 2007), and opportunity cost.

- the structure of the domestic economy, including dependence on and interactions with the petroleum sector.
- (ii) *The companies participating in the sector.* These include national oil companies (NOCs) and/or privately-owned oil companies (POCs).⁴ Companies which are operators of petroleum installations have an obvious role to play in creating value, but even non-operating investors often provide valuable capital and/or expertise. Key sources of value creation include:
- (cost) efficiency of operations (incl. exploration, production, refining, marketing) and overhead spending, as well as investment efficiency;
 - technical excellence, which may support higher reserve replacement and field recovery rates, fewer fuel losses, higher-value product yield (refining) etc.;
 - potential benefits from horizontal concentration (economies of scale) and vertical integration (transaction costs, economies of scope); and
 - corporate strategic choices, such as asset selection, targeting of domestic vs. export markets, etc.
- (iii) *The sector's organization and institutional properties.* The companies' ability and willingness to perform well are embedded within, and affected by, matters of sector organization and governance, which to a large extent are the result of specific policy decisions, including the following:
- the mechanism/regime for capital allocation decisions between different stages of the value chain, and within individual stages – possible choices include free and competitive markets, restricted and regulated entry, or a combination of both;⁵
 - licensing policy (in a broad sense), in order to steer sector activity towards a minimum/maximum level of exploration, production,⁶ refining, number of retail stations etc;
 - the tax system, including subsidies, in order to encourage desired behavior, and to capture a share of the value for the state;⁷
 - the identity, responsibilities and competencies of regulatory authorities;
 - legal and regulatory provisions more generally, including market and trade regulation; and
 - national petroleum and industrial policy, including commercial vs. non-commercial objectives, the development of local supply industries etc.

⁴ The usual designation for the large private sector petroleum firms is “International Oil Companies” (IOCs), but there is widespread acknowledgement that this term is confused, as (i) an increasing number of NOCs are also operating outside of their home country; and (ii) some oil and gas companies are neither state-owned nor international. “POC” is thus suggested as a more appropriate term when distinguishing petroleum firms along the lines of state ownership.

⁵ The first theorem of welfare economics states that any competitive market equilibrium will be Pareto efficient, i.e. resulting in an efficient allocation of resources, but this result is subject to strong theoretical assumptions.

⁶ This is normally referred to as “depletion policy”.

⁷ This also includes fiscal measures to direct production to domestic or export markets, e.g. custom tariffs and export duties, domestic price caps etc.

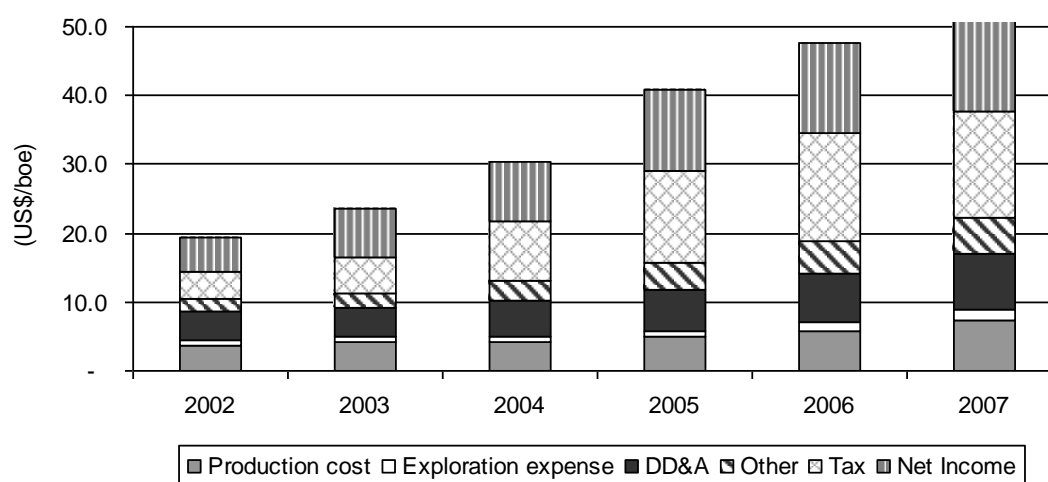
2.2 Empirical illustration: E&P

To illustrate some of the above mentioned issues in the context of upstream exploration and production, we will consider the profit breakdown of large POCs. This is because private shareholder value plus taxation represents a large part of social value.

Figure 2 shows the results of petroleum producing activities (the upstream income statement) per barrel of oil equivalent produced, as reported by the largest OECD-based oil and gas majors – a diversified portfolio of companies operating in largely competitive environments – in their SFAS No. 69 information.⁸ The sum of all costs, taxes and corporate taxes equals the realized sales revenue per barrel, which significantly increased during the period 2002 to 2007 due to high oil prices.

Accounting profits do not necessarily indicate positive value creation, even for private companies, as they ignore e.g. the opportunity costs of capital and of resource depletion, but if we use the sum of private profits and taxation as an approximation of social value creation, then there seem to exist significant rents in E&P.⁹ Over the period 2002-2007 the sum of corporate profits and corporate taxes amounted to between 47% and 60% of revenues.¹⁰ According to some, one possible reason for this is the OPEC cartel of key producing states, colluding on restricting global supply of low-cost production and (c.p.) pushing prices up.¹¹

Figure 2: Results of petroleum producing activities



⁸ SFAS 69 is a reporting standard mandated by the United States SEC for oil and gas producing activities. The information is largely standardised but usually non-audited.

⁹ Economic rent is the excess distribution to any production factor above that which is required to induce the factor's use within the production process or to keep the factor in its current use. Petroleum rent could thus be approximated by the difference between market price and marginal costs. This surplus can then be shared between the land owner and the licensee (investors).

¹⁰ Because revenues are usually reported net of royalties, and other costs include some forms of non-corporate taxes, this measure still underestimates state revenues and thus overall rent.

¹¹ In theory global prices will be set by the cost structures of marginal producers whose output is still required to satisfy demand. For petroleum, their production costs often are a multiple of the lowest-cost Middle-Eastern producers and significantly above median or third-quartile producers. This creates considerable rents for the vast majority of industry participants, as long as the supply of cheap oil is effectively restricted. "Thus, while supply and demand influence price determination, they do so in the context of a highly distorted market." (Stevens 2005, p.20).

Source: UBS Investment Research

Note: Based on SFAS 69 data; value-weighted average of listed OECD-based oil and gas majors (“Global OilCo”). Realised revenues are usually net of royalties. Other costs include e.g. write-downs and impairments, restructuring charges, property taxes, or the value of royalty oil sold on behalf of others where royalty is payable in cash.

Prices (realizations), costs and taxation are key items of the upstream income statement and thus also influence value creation. Each will be discussed below.

Prices

Figure 2 provides clear evidence that underlying oil prices are a primary driver of private profits and taxes payable. But for virtually all firms and states within the petroleum sector market prices are exogenously determined. OPEC – and Saudi Arabia in particular as the world’s only swing producer – has some influence on market sentiment as well as market supply, but the very high price volatility over recent years has shown this influence not to be sufficient to keep prices at a desired level (or within a desired band of prices).

Costs

The costs of petroleum operations, which include operating and investment cost, are very substantial.¹² Several implications follow:

- (i) Efficient cost management at the individual firms, including the competitive tendering for oilfield services, are critical for overall value creation. Any relative inefficiency of operating companies represents a direct loss of social welfare.
- (ii) In order to support national economic development, backward linkages of the petroleum sector with other parts of the domestic economy should be encouraged. But this policy might be at odds with truly competitive tendering. In other words, there is a thin line between targeted support and inefficient subsidies.
- (iii) The upfront capital costs for E&P projects, and their usually long lead times, often necessitate strong partnerships or innovative finance structures, even when positive cash flow from existing developments is available.

A good illustration of the magnitude by which capital costs have increased in recent years is the comparison of depreciation, depletion and amortization (DD&A) charges set out above (upstream depreciation is usually calculated on unit-of-production basis from balance sheet asset values, i.e. capitalized historical expenditures) with current-year finding and development costs per barrel of reserves:

¹² In 2003 Goldman Sachs estimated the global capital expenditure needs for the 50 largest E&P projects to come on stream over the next few years to be US\$210 billion, i.e. in excess of US\$4 billion per project, with the most expensive project (Kashagan in Kazakhstan) estimated at US\$18.5 billion (Goldman Sachs 2003). Since then, upstream capital costs increased very materially: the IHS/CERA Upstream Capital Cost Index rose to 230 points at the end of Q3/2008, up from a base value of 100 in the year 2000 (by Q1/2009 it has fallen slightly to 210 points). Similarly, the Upstream Operating Cost Index doubled from 100 points in January 2000 to 203 points in September 2008, before falling back to 187 points by the end of Q1/2009 (see <http://www.ihsindexes.com/>).

in 2007, the depreciation charge for this group of OECD oil companies was US\$8.14 per barrel of oil equivalent (BOE), while its F&D costs were US\$30.52/BOE.

Figure 2 only shows group averages for exploration expenses and production costs, but these differ very substantially by the country of operation. According to the U.S. Financial Reporting System (FRS), which among others aggregates the upstream costs (defined as finding costs plus lifting costs) per barrel for all U.S. petroleum producers by worldwide areas of operation, 2005-07 average upstream costs in the Middle East were US\$14.85 per barrel, compared to US\$45.98 in Africa and US\$57.20 in offshore U.S. assets. Although these numbers may not be representative of the entire region, the vast cost differences across countries are the result of differences in underlying resource endowment and resource characteristics (geography, geology etc.).¹³

In summary, E&P costs can vary substantially by region/country/asset, but also by asset operator within a comparable environment. Cost differences of the first type are a direct consequence of the resource characteristics, and cannot be influenced by the state or the petroleum firms. Operating (technical) costs differences of the second type are typically a direct consequence of different levels of technical efficiency, and may translate into losses of social welfare.¹⁴

Taxation

The fiscal regime is used by resource-holding states to capture a share of the overall rent, to guide private-sector investment decisions, and to provide incentives for efficient operations. Tax revenue is also usually the single most important contributor to social welfare. In fact, although the companies in our sample are OECD-based firms such as ExxonMobil, BP, Shell or Total, many of which benefit from substantial legacy positions in relatively low-tax countries (U.S., UK etc.), even their effective corporate tax rates over time are between 43% and 55% of pre-tax profits (21%-33% of net revenues).

In addition to corporate and other taxes, the government and/or public regulatory bodies have powers to impose other costs onto industry participants, such as health, safety and environmental expenditures. If correctly priced, these can correct negative externalities and further improve social value creation. If priced incorrectly, however, they might distort the efficient allocation of productive resources.

3 Key stages of the value chain

Having set out the principal stages of the petroleum value chain in Figure 1, this section will provide a very brief introduction to some of their technical properties and the inherent connections between them.

¹³ These numbers only reflect those assets in which U.S. listed petroleum firms had an economic interest. In this sense, they may or may not be representative of the entire region.

¹⁴ Although secondary markets of E&P rights can be used to partially address inefficiencies in the initial allocation process, the transaction may absorb part of the rent that would otherwise accrue to the government (Tordo, 2009, p. 33).

3.1 Exploration and production

The principal primary hydrocarbon resources are crude oil and gas. Crude oil is not a homogeneous material, and its physical appearance varies from a light, almost colorless liquid to a heavy viscous black sludge. Oil can therefore be classified along several dimensions, of which density and sulphur content are two of the most important. Density is measured according to guidelines of the American Petroleum Institute (API) – light crudes generally exceed 38° API, and heavy crudes are those with API gravity of 22° or less. If the sulphur content is less than 1 percent, crudes are usually described as sweet, and sour if the sulphur content exceeds that level. The quality of a crude oil is reflected in its price relative to other crude oils.¹⁵

Box 1: Petroleum resources and petroleum reserves

Petroleum resources and reserves are the starting point of the petroleum value chain. Following is a brief characterization of the industry's reserve classification system, based on the standards of the Society of Petroleum Engineers (SPE).¹⁶ Reserves are those quantities of petroleum which are anticipated to be commercially recoverable from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. As it is not possible to determine in advance the exact size or even presence of oil and gas reserves, reserves need to be estimated by either deterministic or probabilistic methods, and these estimates are always subject to uncertainty. To account for this, three categories of reserves are typically distinguished. Proved reserves are recoverable "with reasonable certainty" under the aforementioned conditions. If deterministic methods are used, the term 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 percent probability that the quantities actually recovered will equal or exceed the estimate. Proved reserves are also often referred to as P90 reserves, 1P reserves, or proven reserves. If the uncertainties around the future production volumes are more pronounced, reserves can also be classified as probable (P50 or 2P) or possible (P10 or 3P) reserves.¹⁷

Although reserve numbers thus are the forecast cumulative profitable output at a certain point in time and under certain pre-defined conditions, they are often mistaken as an estimate of the total amount of petroleum in the subsoil. This is usually called total petroleum in-place or total resource base. Resources then are quantities estimated to be potentially recoverable, but which are either undiscovered or not currently considered to be commercially recoverable with existing technology. The SPE further distinguishes between contingent and prospective resources, as illustrated below.

¹⁵ The exact composition of a crude oil determines the mix of products that can be obtained by refining and the ease of refining. Different products are more or less valuable at any one time, depending on the overall supply and demand for them. Refineries will try to produce the most valuable products if they are able to do so, but the overall supply of refineries of different complexities will limit the overall capacity to supply certain products. Hence, those crude oils which yield a large proportion of more valuable products and which can be treated by a large number of the world's refineries, will command a premium over crude oils which produce a larger proportion of lower value products or which can be processed by only a limited number of refineries (Bacon and Tordo, 2005).

¹⁶ Definitions and more information can be obtained at www.spe.org.

¹⁷ There are further important distinctions, such as proved developed vs. proved undeveloped reserves, but a more detailed discussion is beyond the scope of this brief overview.

Total Petroleum Initially In-Place	Discovered Petroleum Initially In-Place	Commercial	Production			
			Reserves			
		Proved	Proved + Probable	Proved + Probable + Possible		
	Sub-commercial	Contingent Resources				
		Low estimate	Best estimate	High estimate		
				Unrecoverable		
Undiscovered Petroleum Initially In-Place	Prospective Resources					
	Low estimate	Best estimate	High estimate			
				Unrecoverable		

Source: Society of Petroleum Engineers (SPE), RISC Consulting
Note: Categories not to scale

One important consequence of the above definitions is that in order for petroleum to be qualified as a reserve (and proved reserves in particular) under SPE or equivalent standards, detailed information about the reservoirs in question need to be available, and this often entails significant upfront investment. Furthermore, estimates of petroleum reserves are not just uncertain at any given point in time, but can change very substantially over time as the understanding of the geology (petroleum in-place), technological means of extraction, and commodity prices change.¹⁸

The classification of a firm’s oil and gas reserves is sometimes done by internal reservoir engineers at the companies, but – analogous to financial auditors – a number of certified reserve audit firms are also offering their services to enhance the external credibility of the reserve accounts. Although the SPE standard, along with the standard set out by the U.S. Securities Exchange Commission (SEC), is probably the single most common, there is no uniform global approach to the estimation and certification of petroleum reserves, which is a key issue in comparing firm- and country-level data from around the world.¹⁹ Many NOCs and/or nation states do not follow any recognized standards (or do not disclose the basis for their estimates), and even some of the large private POCs fail to employ outside reserve auditors to verify their internal assessment.²⁰

¹⁸ “Growing knowledge lowers cost, unlocks new deposits in existing areas, and opens new areas for discovery. In 1950, there was no offshore oil production; it was highly ‘unconventional’ oil. Some 25 years later, offshore wells were being drilled in water 1,000 feet deep. And 25 years after that, oilmen were drilling in water 10,000 feet deep — once technological advancement enabled them to drill without the costly steel structure that had earlier made deep-water drilling too expensive.” (Adelman 2004, p.18)

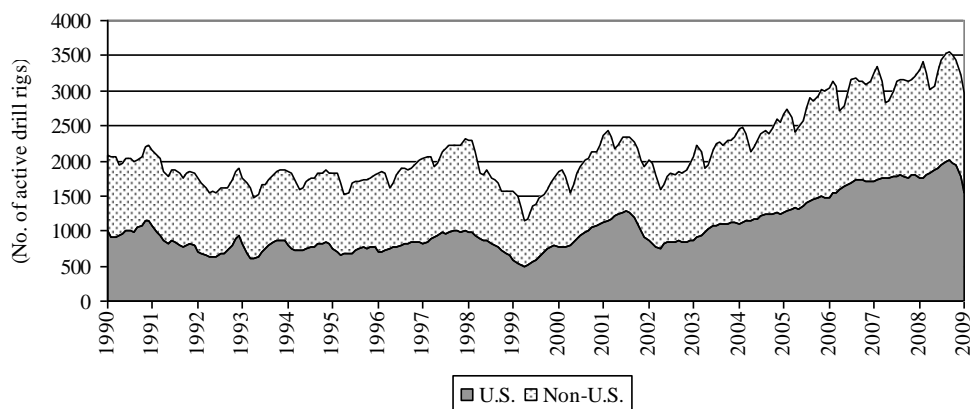
¹⁹ In addition to SPE and SEC, there are other standards, such as the ‘ABC’ reserve system of the Former Soviet Union, Canada’s NI 51-101. Different standards can materially differ in terms of content. Even between SPE and SEC some important differences exist: for example, SEC requires existing prices to determine the commercial viability of reserves (SPE allows an averaging period) and does not allow proved reserves below the ‘lowest known hydrocarbons’ point.

²⁰ Two examples should emphasise the magnitude of these issues: Mexican NOC Pemex reduced its proven reserve estimate from 60 billion barrels in 1997 to 22 billion in 2002 (-64%), mainly as a result

Gas can be found either in separate accumulations from oil (non-associated gas), or in combination with or in solution in crude oil (associated gas). The composition of gas produced at the wellhead varies widely, but in most cases it contains pure natural gas (also known as methane, which is colorless and odorless), natural gas liquids (NGLs) such as ethane, butane, propane, iso-butane and natural gasoline, and a number of impurities including carbon dioxide and water. Dependent on the NGL content, gas is described as either wet or dry. Within the reservoir, gas is also often associated with condensate, a light oil which is gaseous under reservoir conditions. Over the past decade search efforts for gas have been stepped up considerably, whereas before a lot of gas had been found “accidentally” when the real exploration target was oil. Since gas has to be moved by pipeline or by dedicated LNG vessels, developing new markets for it is much more expensive than for oil. This has led to a large amount of “stranded gas”, gas that has little or no commercial value because it has no identifiable market to go.

The identification of suitable sedimentary basins for oil and/or gas exploration is usually done using relatively simple means such as aerial and satellite photography, as well as magnetic surveys. Detailed information of a smaller area is then obtained through seismic surveys, which are considerably more expensive. Through complex computer analysis, the data is interpreted to create an image of geological formations and possible deposits of hydrocarbons. Exploratory drilling is the next step, using drilling rigs suitable for the respective environment (i.e. land, shallow water or deep water). There is considerable ancillary equipment, products and services associated with drilling, and many petroleum companies typically contract an outside services company for these tasks. The market for drill rigs and drilling services is considered a reliable lead indicator for the overall activity and investment level in the industry. Figure 3 below shows the evolution in the active drill rig count index in the last 20 years.

Figure 3: Global active drill rig count (since 1990)



Source: Baker Hughes

If hydrocarbons have been found in sufficient quantities, the development process begins with the drilling of appraisal wells in order to better assess the size and commerciality of the discovery. This is followed by the drilling for full-scale production, and the building of infrastructure to connect the wells to local processing

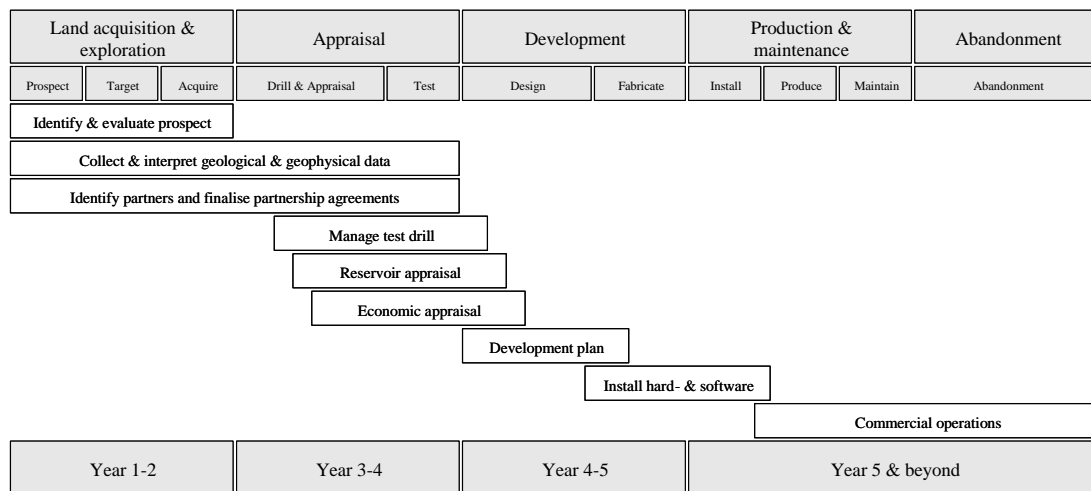
of independent reserve audits according to SEC definition. Royal Dutch/Shell in January 2004 had to reduce its estimate for proven reserves by 20% following an external audit.

facilities or evacuation routes. Onshore infrastructure tends to be less complex and much cheaper than offshore infrastructure.

The speed at which the pressure in the reservoir forces the petroleum upwards is known as the flow rate: it depends e.g. on the properties of the reservoir rock, the reservoir pressure, and in the case of crude oil on the viscosity – in short, the reservoir characteristics. Natural (primary) pressure typically recovers much less than 50% of the oil and 75% of the gas. In order to boost flow rates and overall recovery factors (percentage of hydrocarbons in-place which are recovered commercially) in the face of inevitable natural decline rates, various methods can be used. Secondary recovery methods include the injection of water or gas into the reservoir, or the installation of surface-mounted or submersible pumps. Tertiary recovery methods (or enhanced oil recovery, EOR) involves the use of sophisticated techniques that alter the original properties of the oil. The decisions as to whether – and which – secondary or tertiary recovery methods are appropriate for a certain reservoir often involve trade-offs between commercial (significantly increased production costs, but accelerated and possibly overall greater output) and geological considerations (too aggressive production can damage the reservoir and lead to lower overall recovery factors).

Even on a “standard” upstream project it is not unusual to take up to five years to get from the initial exploration stages to full-scale commercial operation (see Figure 4). For projects with challenging access, geology, or major infrastructure requirements the time horizons involved can be much longer still. These long lead times in project development, coupled with the fact that sudden changes in well-flow management can damage underlying reservoirs (see the section on production/depletion management below), results in structural rigidities in petroleum supply, which often have exacerbated price swings.

Figure 4: Typical schedule for E&P project



Source: UBS (2000), CSFB (2002), author

Most observers agree that the oil and gas industry is a maturing one.²¹ Although there would appear to be no danger of running out of hydrocarbons in the foreseeable future (Lynch 2004; Mitchell 2004; Mabro 2005; Greene et al. 2006;

²¹ Adelman (2004), however, has long emphasised the importance of price incentives and technological progress in the industry’s track record of defying “gloomy” predictions several times in the past.

Watkins 2006), the most traditional onshore and shallow-water offshore fields are rapidly depleting, and new developments (deep-water offshore or remote areas with challenging climate and no existing infrastructure links) are becoming more technically complex and increasingly costly (Goldman Sachs 2003; UBS 2004; Douglas-Westwood, 2008).

3.2 Transportation and storage

From the production site, crude oil and gas need to be transported to the appropriate processing facilities, and from there onwards to be distributed or marketed. Petroleum can also be stored at various points along the value chain for a variety of reasons, including security of supply and price hedging/speculation.

Crude oil is stored in large-diameter holding tanks and is transported by pipeline, truck, railroad and/or tanker to refineries for processing. Well-known long-distance pipelines include the Druzhba pipeline from Russia to Europe, the Trans-Alaskan pipeline, or the recently opened Baku-Tbilisi-Ceyhan pipeline, which connects the Caspian with the Mediterranean Sea, but ocean tankers are the most common form of inter-continental transportation. Many of the key export ports are in or close to the main producing petroleum regions of the world: for example, Saudi Arabia's Ras Tanura facility in the Persian Gulf is the world's largest offshore oil loading facility, with a capacity of approximately 6 million barrels per day. Major import/trading hubs around the world, each with extensive storage and loading facilities, include the Houston Ship Channel, the Louisiana Offshore Oil Port, Rotterdam and Singapore. Refineries, which traditionally have been located near major import hubs to limit additional transportation charges and to be close to oil product demand centers, purchase the crude on the open market or directly from producers.²² Having completed the refining process, oil products can be distributed by the same means as crude oil. Road transport is probably most common, but there also exists an extensive network of product pipelines in various regions of the world.²³

Natural gas may be stored underground in a variety of methods, most commonly in depleted reservoirs, aquifers or salt caverns. The transport options for gas depend on its physical state. Natural gas liquids can be transported either by pipeline or tanker truck, but dry gas (methane) can only be transported by pipeline, and even then not across the seabed of deep oceans, which severely limits the ability to trade natural gas between different regions of the world (clearly the costs for such pipelines might also be prohibitively expensive). An option for long-distance gas exports is liquefied natural gas (LNG), which will be described in more detail below.

Piped gas has to be transported all the way from the production site to the final customer (power stations, industry, domestic and commercial uses etc.), using multiple types of pipelines and pipeline networks along the way. By adjusting the degree of compression in the pipelines, they can also be used as additional storage facilities.²⁴ The physical balancing of an integrated gas network to enable scheduled transits (and possibly short-term trading as well) is a highly complex task. In non-

²² In recent years, in a bid to capture a greater share of the petroleum value chain, some producers have strengthened their refining business, increasing the share of product export vs. crude export.

²³ As an illustration, a map of all Western European refineries, crude oil and oil product pipelines can be downloaded at <http://www.concawe.be>

²⁴ Powerful compressors need to force the gas through any pipeline, otherwise it would just sit statically within it. When storage is unavailable, and current gas flow exceeds market demand, compression can be lowered or stopped until a change in the market or the availability of storage capacity occurs.

exporting countries, the gas producers do not usually own major parts of the gas pipeline infrastructure (transmission grid) and instead sell the gas at the entrance point to the main gas grid. This is somewhat different in major gas exporting countries such as Russia and Norway, where the state-backed producers not only hold the long-term supply agreements, but frequently also an equity stake in the gas pipelines towards the international target markets.

Major pipeline projects require substantial upfront investment, and would not be viable without clearly identifiable (and ideally long-term committed) users, a sound revenue/tariff model and tailored financing. When more than one country is involved, such projects are furthermore often subject to geo-political considerations (Victor et al. 2006). As with any supply or evacuation infrastructure, sunk costs are a substantial risk, but once they have been made they can dramatically improve the economic viability of many actual and potential petroleum projects in the vicinity.

3.3 Refining and marketing

Crude oil almost always needs to be refined into oil products prior to consumption, with the main product categories being fuel oil, gas oil, jet/kerosene, gasoline, naphtha and liquefied petroleum gases (LPG). Gasoil and jet/kerosene are often described as “middle distillates”, gasoline and naphtha are “light distillates”. The three main energy-related uses for oil are transportation, power generation and heating. There is also non-energy or process use, for example as feedstock for the petrochemicals industry. The different end uses differ markedly in their vulnerability to fuel substitution. The transportation and non-energy markets have a low vulnerability, making them relatively captive markets for oil. For power generation and heating, however, the markets can easily switch between fuels, especially between gas, coal and oil, so their price elasticity tends to be higher (UBS 2000).

Oil refining is the process of separating the hydrocarbon molecules present in crude oil and converting them into more valuable finished petroleum products.²⁵ Refineries can consist of a number of different process units that undertake separation, conversion and treatment of oil. The initial stage of a refinery run involves the heating and separation of crude into its constituent parts in a distillation column. Then the different fractionations are directed to conversion units to be chemically altered through the introduction of heat, pressure, catalysts or hydrogen. The output of these conversion units is then treated or blended. Refineries are usually categorized by size and configuration. The configuration or sophistication of a refinery refers to the technical capabilities and flexibility to process different kinds of crude feedstock into a large number of different products.

Because of their chemical properties different crude oils produce very different yields when refined. Crudes that are lighter (in terms of density) and sweeter (in terms of sulphur content) naturally produce a higher yield of lighter, more valuable products such as gasoline and less of lower-value products such as residual fuel oil²⁶, but these crudes also trade at a premium in the market. Refiners will strive to process an optimal mix of crude oil (crude slate), depending on each refinery’s individual

²⁵ Preston (1998) is a good introduction to the history of refining, key technical terms and sources of operational information.

²⁶ Fuel oil has long been used as an energy source in heavy industry, but has become unpopular in developed countries for its high pollution and undesirable combustion. It can also be processed into petroleum coke and asphalt/bitumen.

configuration of process units, current and anticipated product prices, the desired product mix (product slate) and the relative price of crude oil available.

The key driver of oil product demand patterns is a country's or region's level of economic development. Whilst in developing countries heavy fuel oil still is in considerable demand for industrial uses, developed countries with their service economy and focus on personal mobility require mostly middle and light distillates. Oil product demand usually follows a seasonal pattern: it is interesting to note, though, that the U.S. is the only major consuming market where seasonal demand peaks in summer. This is due to the exceptionally high demand for gasoline relative to other oil products (motor and aviation gasoline account for 46% of oil product demand in the U.S., but only for 22% in the EU) and the so-called "driving season" in summer. In other countries of the northern hemisphere, the importance of heating oil, propane and kerosene as heating fuels create a winter peak in the seasonal demand pattern (UBS 2000; BP 2008).

Refining is a global, highly cyclical business in which profitability is sensitive to marginal changes in product supply and demand. The principal measure of profitability is the gross refining margin (GRM), which is calculated as the difference between the revenues received and the cost of feedstock plus other cash costs such as labor, maintenance and working capital. GRM excludes non-cash costs such as depreciation, so that a positive GRM may still translate into an accounting loss. The margin after non-cash costs is the net refining margin. Both margins are usually expressed on a per-barrel basis. Although refining margins are unique for each plant, refineries in the same region tend to experience similar margins, because of the same product prices in their output market, the same availability of crude grades and therefore often similar technical configurations. The three primary refining centers in the world, for which refining margins are typically quoted, are the U.S. Gulf Coast, North-Western Europe and Singapore.

Marketing refers to the distribution and sale of refined products, whether through wholesale or retailing in petrol stations. Road transportation fuels are primarily distributed at retail stations, heating oil is usually delivered to residential and industrial customers, kerosene is purchased directly by individual airlines and airports, and residual fuels are also sold directly to shipping companies, utilities and industrial plants. Marketing margins (pre-tax pump prices less spot prices for oil products) tend to be more stable than refining margins, and overall profitability of petrol stations is further enhanced by the ever increasing non-fuel sales such as convenience goods.

3.4 Gas processing and marketing

Many petroleum companies are involved not only in the production of gas, but also in its processing and marketing. Usually, gas must be processed in dedicated plants (so-called fractionators) to become suitable for pipeline transportation: NGLs and impurities are extracted from the gas and the NGLs are further fractionated into their constituent parts and sold. In addition to piped natural gas and NGLs, liquefied natural gas (LNG) is a third core "gas product", and gas-to-liquids (GTL) might also have significant future market opportunities.

The distribution of piped gas to the end consumer is usually done by utility companies, but petroleum firms might well be involved in the longer-distance transmission business, or in direct deliveries to industrial users, power plants etc.

NGLs are also sold to industrial, wholesale and retail clients (in the latter case usually through petrol stations). The GTL process converts natural gas into a range of high-quality colorless, odorless and biodegradable products normally made from crude oil, such as transport fuel, naphtha and oils for lubricants. Although so far the technology has been largely applied in smaller demonstration plants, Qatar is currently building several world-scale GTL facilities in order to diversify its gas commercialization strategy.

Of the 2007 total production of 2,940 bcm of gas only 550 bcm (18 percent) are traded internationally by pipeline and 226 bcm (8 percent) are currently traded in the form of LNG, implying that about three quarters of global output is consumed domestically (BP 2008).²⁷ However, due to declining indigenous production and the expected increased significance of gas in the future, the trade in LNG is projected to grow strongly over the next years and decades. At the moment, Japan and South Korea still account for more than half of all LNG imports, but the market is bound to become more geographically balanced over time.

The technical process of LNG involves three stages: first, the processed natural gas is progressively cooled to minus 160°C when it becomes liquid at atmospheric pressure and shrinks to one six hundredth of its gaseous volume. The liquefaction process is done in dedicated LNG plants close to the wellhead and gas processing plant. The LNG is then stored in insulated tanks before being loaded into dedicated cryogenic tankers for shipment. At arrival in the destination, it is received at an LNG receiving terminal, where it is re-gasified and injected into the local gas grid. LNG projects are highly capital intensive and it is common practice to enter into at least 20-year supply contracts in order to reduce project risk and to justify the investment budget. Traditionally, ownership of the LNG plant and export terminal used to be with the upstream petroleum company, whereas the import terminal and tankers were owned by the receiving company, in most cases an electric utility. Because of the increasing level of competition of LNG producing sites worldwide, however, major oil and gas firms now increasingly also hold an equity stake in the receiving facility to ensure an off-take for their LNG production.

3.5 Petrochemicals

Petrochemicals are chemicals made from crude oil and natural gas and account for approximately 40% of the world's chemical market. The two main groups of primary or base petrochemicals are olefins (including ethylene, propylene and butadiene) and aromatics (including benzene toluene and xylenes). Chemical products based on these base materials include polyethylenes (PE), polyvinyl chloride (PVC), styrene and polystyrene (PS) as well as polypropylene (PP), which in turn are the basis for a wide range of everyday products such as pipes and tubing, plastic bags and bottles, telephones, coffee pots, electronic components and car tires.

The oil industry became involved in petrochemicals from the 1920s, since naphtha (from refineries), natural gas and natural gas liquids constitute the principal feedstock. Because of the advantages of logistical proximity, refineries and petrochemicals plants are often situated close to each other and often have pipeline linkages between them. The most common profitability measures in petrochemicals are cash margins

²⁷ The BP Energy Review does not provide a breakdown for NGLs and GTL, but it is plausible to assume that NGLs are largely consumed domestically, and that GTL output is still insignificant.

per ton, usually reported for the two main “upstream” products ethylene and propylene.

4 Value creation through integration

The possible benefits of integration – horizontally and vertically – have long been the topic of petroleum value chain analyses. Having reviewed the individual stages of the petroleum value chain, the question arises as to the potential for incremental value generation through such integration.

Regarding *horizontal concentration*, the benefits from economies of scale in most activities of the value chain are widely acknowledged. Petroleum projects are highly capital intensive, have long lead times, and are inherently risky (Stevens 2005). In E&P particularly, scale helps to access better funding, to diversify investment and development risk, and to serve as long-term insurance to partners such as host governments. Due to the high financial and operational risks involved, oil and gas companies are usually partnering each other in E&P projects, while still competing at corporate level. Despite these frequent partnerships, technical expertise and project control are considered key in building a competitive advantage within the industry, and these can be enhanced by scale-related R&D investment and broad operatorship experience.

The ongoing consolidation trend within the private petroleum sector (increasingly also involving NOCs as acquirers of petroleum assets) is testament to the benefits of economies of scale (or, at least, the perceived benefits). But large-scale divestitures are also very common: over the period 2002-07, in fact, UBS Investment Research shows the value of disposals at the “Global OilCo” companies (see Figure 2) to be 75 percent higher than the value of acquisitions. This shows that scale in itself is not always beneficial and that careful selection of assets is required in order to offset any diseconomies of scale (such as management distraction). A focus on certain core areas with shared infrastructure, for example, is one plausible and frequently chosen approach. However such a strategy may not deliver the best possible diversification of geological risks, which is another driver of sector consolidation or satisfy the desire for global upstream scale.

As a country strategy, there are natural resource limits in building a broader domestic E&P footprint, as well as issues of appropriate depletion strategy (discussed below in more detail). In other segments of the value chain, however, some countries have successfully managed to attract substantial investment beyond their domestic requirements. Singapore and the Netherlands are examples in refining, storage and oil trading, although both benefited from infrastructure advantages including large natural ports along busy trading routes.

Vertical integration is another prominent feature of the petroleum industry, although the details of integration have changed over time. It can take two principal forms (Luciani and Salustri 1998; Bindemann 1999; Stevens 2005): financial vertical integration occurs when subsequent stages of the value chain are owned by one holding company, which controls their cash flows; operational vertical integration occurs when there is a physical exchange between those different stages of the value chain, i.e. crude and products move in between them.

Before the wave of nationalizations in the 1970s, POCs used to be both financially and operationally integrated. Key motivations for such integration were to secure

sources of supply, to secure off-take markets, to create entry barriers, to circumvent taxes, to eliminate the profit margins of intermediaries or to practice price discrimination (Bindemann 1999). Integration also facilitated logistical operations such as storage, and before the oil price shocks caused significantly lower transaction and information costs compared to markets (which were non-existent or highly inefficient at the time) (Stevens 2005). Following the nationalization of Middle East oil properties and the two oil price shocks, POCs retained integration by ownership, but started to move away from operational integration to the increased use of intermediate markets, which became more transparent, liquid and reliable. Shell was the first company to free its refineries from the requirement to purchase oil from within the group (Cibin and Grant 1996). Internal transactions were increasingly conducted at arm's length, giving individual divisions more autonomy. Furthermore, almost all POCs established dedicated oil trading divisions (ibid). The increased sophistication and liquidity of oil markets enabled further disintegration, reduced barriers to entry and allowed a new set of entrants (such as dedicated refiners and retailers, in the latter case particularly supermarkets) into the industry (Davies 1999). Today, whereas financial vertical integration is a prerequisite for operational vertical integration, the reverse is not true – intermediate markets can substitute for operational vertical integration.²⁸

Given the prominence and longevity of the major integrated POCs (see also Chapter 2 on the history of the industry) there often is an assumption as to the inherent advantages of financial and/or operational integration, but such perceived benefits at the corporate level have proven difficult to pin down in empirical studies (Bindemann 1999).

Vertical integration at the country level, in the sense of deliberate industrial policies to guide or encourage diversification along the value chain, might be pursued to diversify price or demand risks to the economy, to capture a larger share of value-adding processes, or simply to respond to changing domestic and international demand. The economic literature suggests that vertical integration makes more sense in the case of asset specificity (Williamson 1985) than in the case of commodity markets. For example, when owners or producers of very heavy or very sour crudes cannot be assured of sufficient refinery demand on the open market, then there is an incentive for vertical integration of E&P and R&M. Kuwait's strategy of overseas refinery acquisitions can (partially) be seen in this light (Marcel 2006; Stevens 2008). A second example is the presence of abundant and cheap resources that cannot be easily transported, like in the case of Qatar's natural gas. In this case, it is possible to move some of the downstream industrial users to the source of gas, because the savings on feedstock costs more than compensate for higher transport costs (and potentially higher production costs) of the final product. This industrial relocation supports larger production volumes than would otherwise be possible, and thus contributes to horizontal concentration at the country-level. In Qatar's case potential additional benefits are those of economic diversification, and domestic skills development.

²⁸ In light of the recent liquidity crisis in the financial markets, one should point out that petroleum markets have worked perfectly well over the past years and decades, but that "low-probability high-impact" events could compromise market efficiency.

5 Key policy choices

As set out earlier in this Chapter, a company's ability and willingness to perform well is embedded within, and affected by, matters of sector organization and governance, which to a large extent are the result of specific policy decisions. These include, among others:

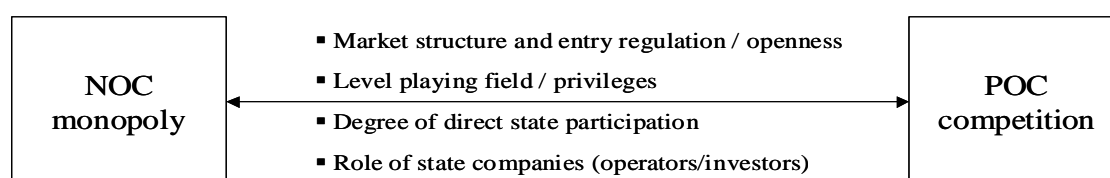
- national petroleum and industrial policy, including degree of direct state involvement, commercial vs. non-commercial objectives, industrial linkages to other sectors of the economy etc.;
- the mechanism/regime for capital allocation between different stages of the value chain, and within individual stages;
- market structure (monopoly, oligopoly, competition) and barriers to entry;
- the identity, responsibilities and competencies of any regulatory authorities;
- general legal and regulatory provisions, including market and trade regulation;
- licensing policy to steer sector activity towards a minimum/maximum level in terms of exploration, production, refining, number of retail stations etc.;
- upstream depletion policy; and
- the tax system (as well as any subsidies) in order to encourage certain behavior and to capture a share of the value for the state.

A thorough discussion of each of these policy choices is beyond the scope of this Chapter. Instead, we limit ourselves to four of these important issues – industry participation, licensing and petroleum contracts, taxation, and depletion policy – which will be briefly introduced, and their relationship to value creation discussed.

5.1 Industry participation

The assessment of the competitive landscape of any country's petroleum sector is complex, as it is determined by several interdependent variables, all of which influence the participants' ability and willingness to create social value. At one end of the continuum of options is a pure monopoly held by a state-owned entity without any outside participation; at the other end is a perfectly competitive market without any entry regulation or direct state intervention; in between are numerous possible combinations of variables, as set out in Figure 5.

Figure 5: Continuum of participation options



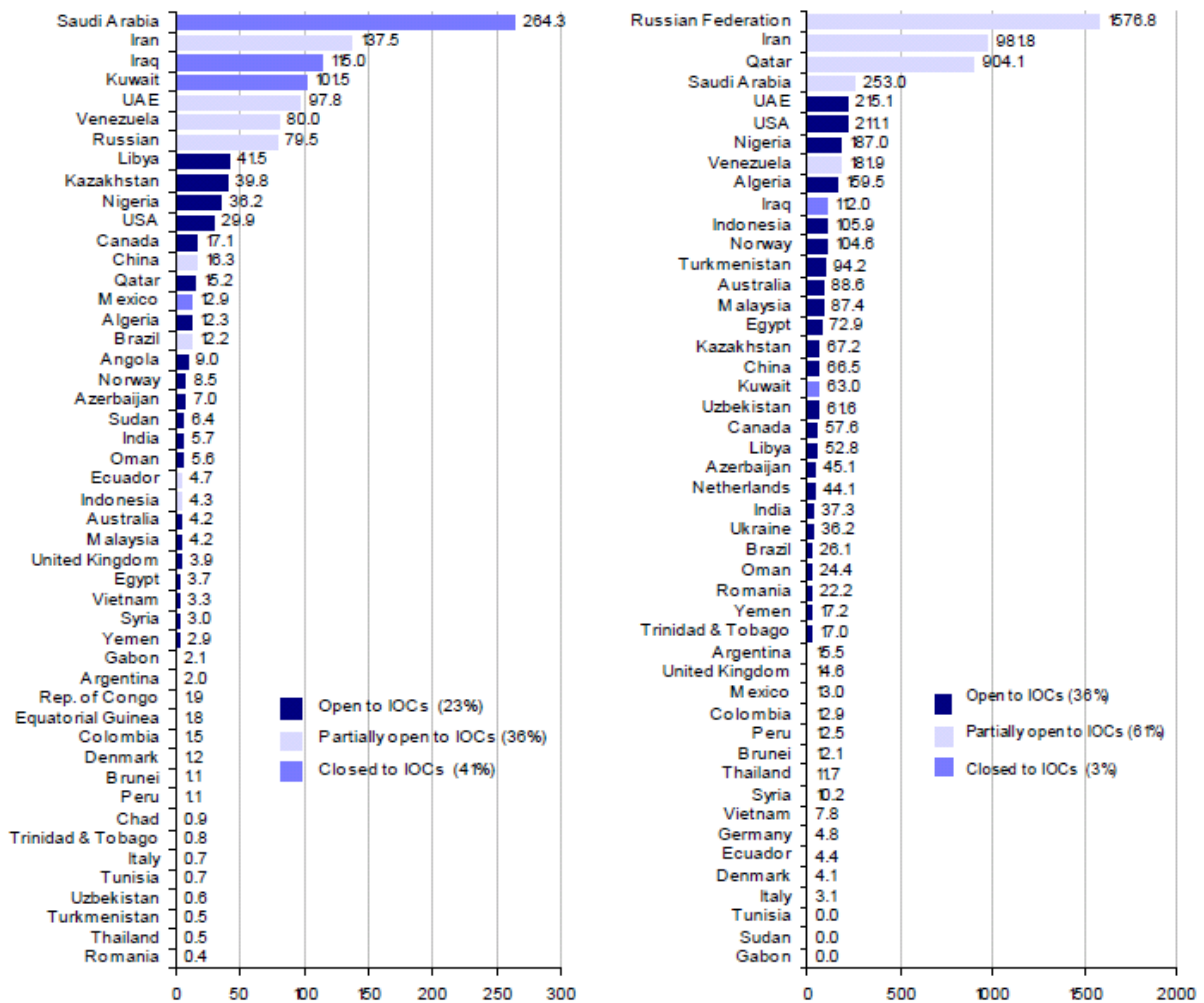
Source: Author.

In reality, probably no country has implemented either of the pure-form options. Saudi Arabia and Mexico, for example, have a state monopoly on upstream equity ownership, but private oil service contractors face few restrictions, and Saudi Arabia

now provides limited opportunities for equity participation in natural gas projects. At the other end of the spectrum, even the most market-oriented countries usually set pre-qualification criteria for participation in auctions, which may reduce the effective degree of competition and market contestability. In many countries there are different policies for the different stages of the value chain.

Focusing on the narrower criterion of outside access to petroleum reserves, Figure 6 categorizes the largest resource-holding nations into those that are fully open, partially open, or closed to outside participation.

Figure 6: Access to oil reserves (left, in billion barrels) and gas reserves (right, in trillion cubic feet)



Source: UBS (2008), BP (2008)

Note: Since publication of this chart, Iraq has started limited auctions of petroleum licenses

5.2 Licensing and petroleum contracts

The details of petroleum licenses and contracts, together with the fiscal framework (see below) provide the basis for many technical and commercial decisions by petroleum firms (e.g. where to invest, how much to invest, whether or not incentives

for cost-efficiency exist). Nation states can use a licensing system as a tool to shape industry structure, e.g. by deciding on the frequency and area coverage of any licensing (whether by auction or negotiated deal), by setting particular economic incentives for participation, or by imposing conditions such as mandatory involvement of the state.

Box 2: Classifying petroleum contracts

Three generic types of contracts exist (Johnston 1994; Johnston 2007; Tordo 2007):²⁹

- *Concessionary system.* Best known for its application in OECD countries and often considered the most liberal choice, it was virtually the only arrangement available before the late 1960s. The licensee obtains a lease from the government for a fixed period of time, is responsible for all investment (and thus owns) all E&P equipment for this period; upon expiry of the concession, the installation often passes to the state, but the investor is typically liable for abandonment. The investor takes full title to reserves and production at the well head, net of any physical royalties. In addition to physical or cash royalties, taxation typically includes a specific petroleum tax as well as the general corporate tax.
- *Production-Sharing Contract (PSC).* There exist a multitude of PSCs around the world, with many differences between them, but many share some common features. Title to the production and reserves in the ground remains with the state or its NOC (often the partner in a PSC),³⁰ although the contractor funds the entire development (after submitting the development plans and cost estimates for approval) and puts its own capital at risk. Ownership of the installations often immediately passes to the state. The contractor is then reimbursed through a specified part of the production called ‘cost oil’. The remainder of the production, the ‘profit oil’ is shared between the contractor and the state. Usual corporate profit tax rates apply to the profit oil captured by the contractor. PSCs sometimes also involve an additional upfront royalty payment (in cash or in kind).
- *Service contract.* The contractor is usually paid a cash fee for providing the service of producing petroleum on behalf of the host nation. Johnston (2007) lists three types of cash fee that have been observed in practice; a fixed fee per barrel produced, a fixed fee as a percentage of costs (uplift), or a variable fee as a percentage of gross revenues. Under all three constructs the service contractor provides all capital associated with exploration and development, but has no title to reserves or production. Instead, if the project starts commercial production part of the sales revenue is used to reimburse the contractor’s costs and to pay its fee, which is often taxable.

In essentially all countries outside the U.S. the subsoil is publicly (state) owned, irrespective of the ownership of the surface land, or the state retains a veto on its use

²⁹ PSCs and Service Contracts are “contractual” systems vs. the alternative “concession” system.

³⁰ SEC rules permit private contractors to book reserves from PSCs if they hold the right to develop and extract, if production is reasonably certain, and if the contractor’s own capital is at risk. As a reporting requirement, reserves from PSC contracts must be disclosed separately from other reserves.

(Mommer 2002).³¹ Where the subsoil is publicly owned, government can either grant a monopoly right to one particular party, or put into place a licensing system for the participation of multiple parties. Exploration acreage is usually auctioned or awarded after negotiations with invited parties. Bidding often takes the form of a package of commitments to the host country, such as commitments to develop infrastructure, to spend a minimum amount of money on exploration, to use local contractors to a certain extent, or to drill a minimum number of wells.

In recent years licensing (and taxation) regimes all around the world have become increasingly varied, frequently reflecting historical or regional preferences. Their analysis should always be based on substantive content rather than formal design or type. Waelde (1995) points out that “the form of the contract is much less of the essence than the actual content, i.e. how the major functions and issues (management and control; risk assignment; revenue sharing) are being regulated.”

5.3 Taxation

Taxation is a critical consideration. The petroleum sector is among the most heavily taxed sectors, and taxation impacts on contractual relationships, asset selection, behavioral incentives, the dynamics of supply as well as demand, and most obviously on the financial position of the various parties involved. Ideally taxation should not alter allocative decision-making (and possibly even correct for market failures such as unduly low private costs of environmental pollution). This would support efficient behavior and maximize total welfare. If fiscal incentives are distortive, however, e.g. by disincentivizing cost savings or by encouraging excess investment, then this will result in net welfare losses.

In upstream oil and gas, total government take – which is the government share in economic profits – globally varies from about 40 percent to well over 90 percent (Johnston 2007). In the years 2002 to 2008, with significantly rising commodity prices, many states have increased the percentage of government take from upstream oil and gas. Average fiscal terms can tighten in a number of different ways: (i) automatically, by virtue of the fiscal terms themselves (contractually or legally); (ii) by means of time, when new concessions are awarded on different terms than previously awarded ones; (iii) through competition as oil companies bid the terms or bid the signature bonuses they are willing to pay up front; or (iv) through retrospective adjustment.

An important consideration when determining appropriate levels of government take is the potential trade-off between near-term state rent capture and longer-term value creation. Given the uncertainty that characterizes petroleum exploration and production activities, maximizing the NPV of rent capture might discourage longer-term investment, which in turn forms the basis for future rents to be created.

In downstream oil, significant consumption taxes are levied by most industrialized countries on top of the taxes on crude oil. Looking at a consumption-weighted average of main refined product groups in the EU in 2003, only 28 percent of the final sales price was accounted for by crude oil, whereas 62 percent of the final price was due to taxes (incl. VAT) and the remaining 10 percent was refining cost and company

³¹ The U.S. in principle has private subsoil ownership, but ca. 30% of all land onshore, and deeper offshore areas (more than three nautical miles from the shore) are federal land. Offshore areas within the three mile radius are owned by the individual U.S. states.

profit (OPEC 2005). For selected products such as gasoline, only 12 percent of the final price was accounted for by crude oil (Stevens 2005).

5.4 Depletion policy

Mineral wealth is a non-wasting but exhaustible resource, and production of oil and gas can be considered as a conversion of hydrocarbon wealth into monetary wealth at a largely discretionary point in time. The first crucial set of decisions a government faces is whether or not to explore for petroleum, at what pace to explore, and who should undertake such exploration (Tordo, 2009). If the reserve base is assumed to be fixed, then maximization of social welfare will be achieved by the appropriate pattern of production (i.e. drawing down the inventory) over time. This pattern of using up existing reserves is measured by the production rate (annual production as percentage of proven reserves) and indicates different approaches to depletion management (or depletion policy). In principle, the issue of portfolio composition – whether to hold wealth as petroleum in the ground or some other assets above ground – could be separated from the issue of expenditure decisions; unfortunately the two issues are linked in practice (Stiglitz 2007). The issue of implementing an appropriate depletion management is far from trivial, and at least the following factors play a role:

- *“Best oilfield practice”*: In a technical sense, reservoir characteristics often necessitate certain best-practice development plans – deviations might result in permanent damage to the reservoir. Fields also have a natural decline rate of production, linked to the reduction in primary reservoir pressures over time.
- *Politics*: Nation states might have entered international commitments on productive capacity, output etc., which limit discretionary decision-making.
- *State budget*: Public finances might dictate accelerated production schedules. Better knowledge of the size of petroleum reserves provides an input for the design of sustainable macroeconomic policies and for improving intergenerational equity through the choice of current consumption rates (Tordo, 2009, p. 4).
- *Public pressure on spending*: Increased public income might result in pressures to spend the money, irrespective of suitable re-investment opportunities
- *Domestic economy*: Suitable re-investment opportunities for monetary income from petroleum operations may encourage accelerated production schedules; a lack thereof, dangers of hyper-inflation or of adverse changes in foreign exchange rates (“Dutch disease”), or a lack of potential production linkages to the rest of the domestic economy, however, may discourage more aggressive depletion policies.
- *Institutional framework / national governance*: Government as a whole, or certain interest groups within or outside government might be tempted to direct funds from petroleum production to inappropriate or even illegal purposes, if no appropriate checks and balances exist. In such cases “the ground just might be the safest place for the asset” (Humphreys et al. 2007b, p.15).

- *Resource curse*: Related to both the domestic economy and institutional framework is the apparent failure of many states to translate a wealth of natural resources into sustainable economic development (“resource curse” thesis).³²
- *Price expectations*: Changes in the prices of oil and gas materially affect the value of the assets still underneath the ground.
- *Cost expectations*: “[I]n cases where costs of extraction are currently high, and might be lowered over time with the progress of technology, the return to waiting may be higher than on any other investment the government might make.” (Stiglitz 2007, p.39)
- *Time value of money*: Petroleum in the ground does not earn an automatic interest or income (unless prices or costs change); dependent on the magnitude of the potential investment return on non-petroleum assets, and on the social discount rate, the time value of realized production gains might differ considerably.³³ The earlier the extraction date, the higher (*ceteris paribus*) the potential benefits.

To further add to the difficulty of identifying an “appropriate” depletion management, there exists a long-standing debate over the notion of a fixed inventory of reserves, given their dynamic influence factors outlined earlier in this Chapter.³⁴

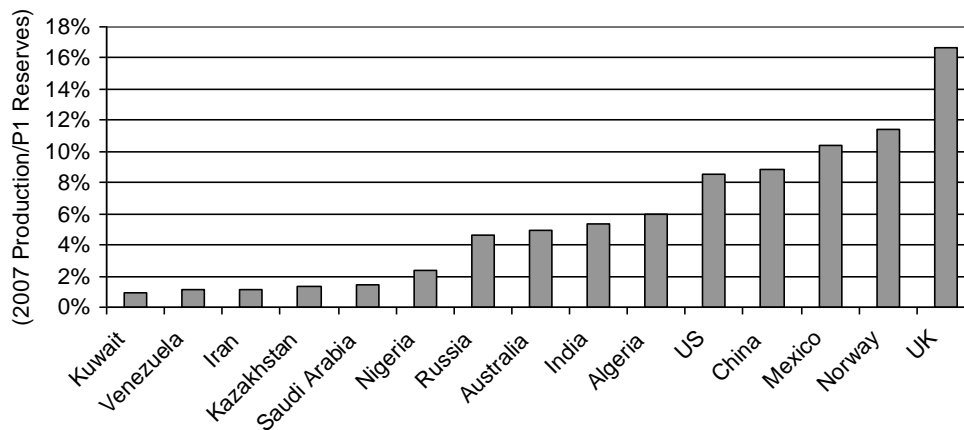
Depletion management can refer to individual petroleum reservoirs, to connected areas of production, or to the aggregate national level. It can be directly and explicitly imposed by the government, directionally guided using instruments such as the licensing system, or developed bottom-up through the (largely unregulated) choices of individual project operators. Empirically, there are wide differences in production rates between individual countries (Eller et al. 2007; Victor 2007; Wolf 2009).

³² Resource curse has been treated in detail elsewhere (Wijnbergen 1984; Auty 1993; Karl 1997; Leite and Weidmann 1999; Stevens 2003; Humphreys et al. 2007a). Sachs (2007) points out that the idea of oil being a “curse” is only partly true, as oil-rich states often outperform neighbours that lack oil in GDP as well as development indicators such as life expectancy, child mortality, school enrolment and infrastructure provision. Collier (2007) and Collier and Goderis (2007) reach different conclusions.

³³ See Boardman et al. (2006) and Moore et al. (2003) for a discussion on the social discount rate.

³⁴ “[I]n some times and places the oil does run down. [...] But the ‘running out’ vision never works globally. At the end of 1970, non-OPEC countries had about 200 billion remaining in proved reserves. In the next 33 years, those countries produced 460 billion barrels and now have 209 billion ‘remaining.’ The producers kept using up their inventory, at a rate of about seven percent per year, and then replacing it. The OPEC countries started with about 412 billion in proved reserves, produced 307 billion, and now have about 819 billion left. Their reserve numbers are shaky, but clearly they had — and have — a lot more inventory than they used up” (Adelman 2004, p.18). See also CERA (2006).

Figure 9: 2007 depletion rates in selected countries



Source: BP (2008)

6 Conclusion

The petroleum value chain encompasses exploration and production of oil and gas, transportation and storage, refining and marketing of oil, processing and marketing of gas, as well as related activities such as oilfield services and equipment and petrochemicals. Together, these processes transform underlying petroleum resources into useable end-products valued by industrial and private customers. Along the value chain activities are inherently inter-linked, and such linkages might occur within or across individual firms, and within or across national boundaries.

Integration along the value chain – whether horizontally or vertically – has often been used to generate incremental value. The benefits from economies of scale from horizontal integration in most activities of the value chain are widely acknowledged, particularly with respect to exploration and production activities, where scale helps industry participants to access better funding, to diversify investment and development risk, and to serve as long-term insurance to partners such as host governments. As a country strategy, there are natural resource limits in encouraging exploration and production activities, as well as issues of appropriate depletion strategy. In other segments of the value chain, however, some countries have successfully managed to attract substantial investment beyond their domestic requirements. Vertical integration at the country level, in the sense of deliberate industrial policies to guide or encourage diversification along the value chain, has been pursued with mixed success by some countries to diversify price or demand risks to the economy, to capture a larger share of value-adding processes, or simply to respond to changing domestic and international demand.

Broadly, three potential sources of social value creation from petroleum operations can be identified: (i) exogenous context and conditions; (ii) the companies participating in the sector, including their operational and strategic set-up, priorities and capabilities; and (iii) the sector's organization and institutional properties. Among the policies choices that determine the institutional environment, four were briefly discussed in this Chapter: industry participation, licensing and petroleum contracts, taxation, and depletion strategy. Each of these can be expected to have a material impact on overall levels of value creation, but the actual policy choices made by countries around the world vary considerably.

The interactions between these sources of value creation – which will be analyzed in more detail in Chapter 4 – are complex and dependent on the specific context (i.e. country and temporal conditions); “blueprint” solutions to successful value creation thus would be difficult to suggest. But experiences from around the world still provide useful insights into successful institutional arrangements and operating strategies – they are, in fact, the only data points available – and, when analyzed diligently, can serve as a basis for future decision-making.

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