

6 Natural gas

Experience and issues

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1 Introduction

Sales of natural gas are growing significantly around the world. Who benefits from this production is, in large part, determined by the fiscal terms applicable in the various links of the gas value chain. Fiscal policies can influence the price received by producers and processors of gas as well as the extent and timing of the recovery of investment costs. Fiscal policies can also drive different operational and ownership structure of gas projects.

This chapter discusses the various issues that need to be considered by policymakers when designing an appropriate fiscal regime for the development of their natural gas resources.

While many aspects of the natural gas business are very similar to oil, there are some significant differences (which are discussed in Section 3D on petroleum economics) that result in a very different investor perspective on gas projects, compared to their oil equivalent. Moreover, in many countries the development of natural gas has occurred only recently whereas oil has been produced for many years. In particular, the export of gas, primarily via liquefied natural gas (LNG) schemes, has only really emerged in the last 15 years. These developments have generated a number of particular issues which fiscal policymakers need to address and these are also considered in this paper.

To put the fiscal policymakers' task into perspective the chapter starts with a description of the growing size of the natural gas business and how its 'value chain' is created. This introduces both the 'size of the prize' and some of the major issues involved in determining how this prize gets distributed between the different participants in the business, including government.

2 Background

A Natural gas: resources and demand

The supply of natural gas worldwide has increased by 25 per cent between 2000 and 2008 (from 80 trillion cubic feet per annum (Tcfpa) to 102 Tcfpa) and is expected to increase to over 140 Tcfpa by 2020, as illustrated in Figure 6.1. In

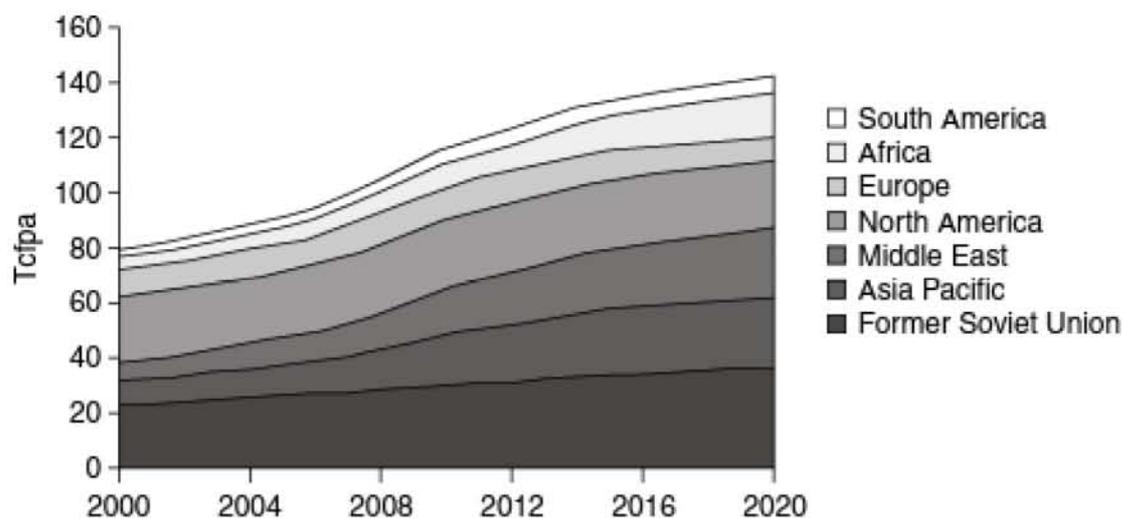


Figure 6.1 Global natural gas supply 2000–2020 (source: Wood Mackenzie (3Q 2008)).

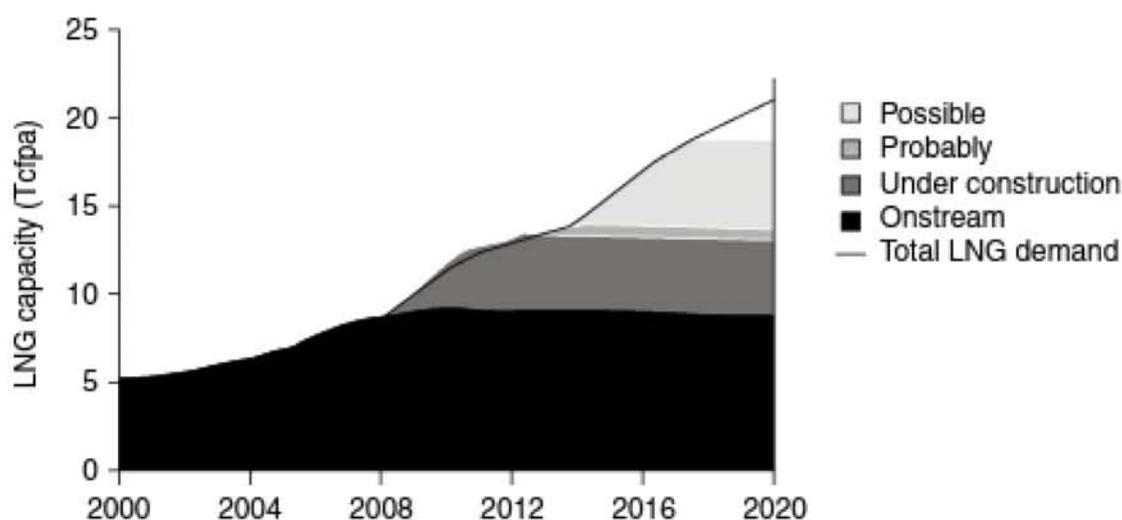


Figure 6.2 Global LNG supply 2000–2020 (source: Wood Mackenzie (3Q 2008)).

Note

1 Tcfpa = 21.3 mmtpa.

the same period the amount of gas volumes traded as LNG has doubled (from 5 Tcfpa to 10 Tcfpa and is expected to double again by 2020 (~20 Tcfpa) as shown in Figure 6.2, taking LNG's contribution to overall supply from 6 per cent in 2000 to 14 per cent in 2020.

Figure 6.3 illustrates the extent of the divergence between the regions which own the remaining gas resources and those which currently consume the most gas. Seventy per cent of remaining proven reserves is in the former Soviet Union and Middle East, which currently account for only 30 per cent of consumption. By contrast, Europe and North America make up nearly half of global current consumption but have only 8 per cent of remaining reserves. This picture may change if the perceived scale – and commerciality – of the recent shale gas discoveries in the US becomes proven.

The opportunity for new LNG projects to meet the growing dependence on imported gas in the main demand centres has stimulated the industry's appetite

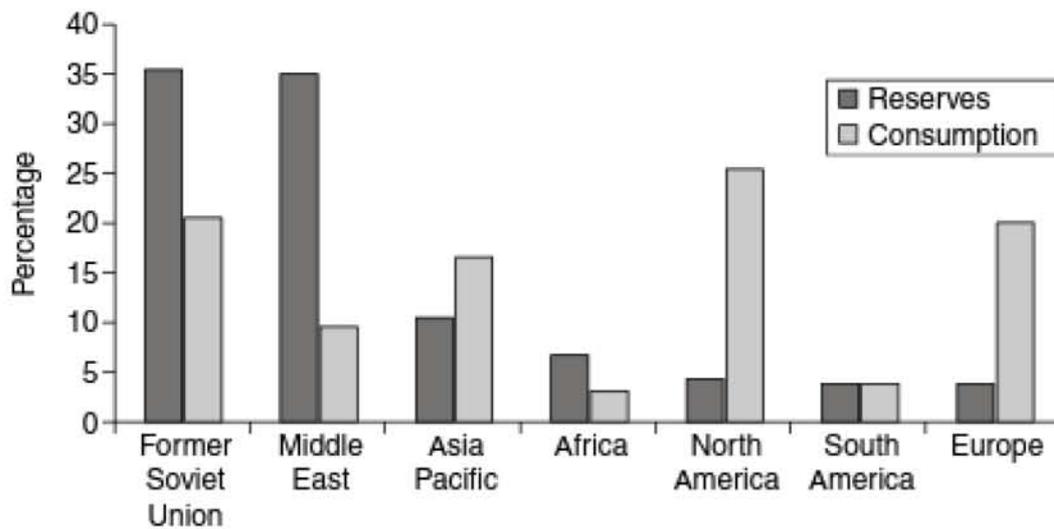


Figure 6.3 Global natural gas reserves and consumption (% world total) (source: Wood Mackenzie (3Q 2008)).

Note

US reserves source: BP Statistical Review of World Energy 2008.

for gas in resource-rich countries and companies are increasingly keen to acquire gas reserves. A major stumbling block for them is the fact that gas reserves remain largely under state control in many of these countries. The inability of domestic consumers to pay anything like the gas prices received in the developed countries has traditionally meant that local gas projects have largely been developed by governments, which have taken ownership of the gas reserves. The emergence of export markets for gas mean that governments are now keen for increased export revenues, but remain equally keen that abundant local gas supplies replace oil and other primary fuels in power generation and industrial projects and contribute to the expansion of these activities. To promote investment in domestic projects, therefore, some governments have begun to tie investor's rights to export gas with obligations to develop local gas projects.

The ability of governments and industry to meet growing domestic and export demand for natural gas is influenced by many factors such as exploration success, LNG marketing advantages, corporate positions and geopolitics – all of which are uncertain and subject to change. Where the parties can influence outcomes is in the design of an appropriate taxation policy to ensure risks are balanced by rewards along the value chain. The design of a suitable fiscal policy for natural gas presents government with a number of simultaneous policy issues, notably gas pricing and equity participation, and these are discussed in this chapter.

B Natural gas: value chain

Getting natural gas from the drill bit to burner tip involves a chain of operations, as illustrated in Figure 6.4. Depending on the ultimate consumer of the gas produced, natural gas extracted from a reservoir will:

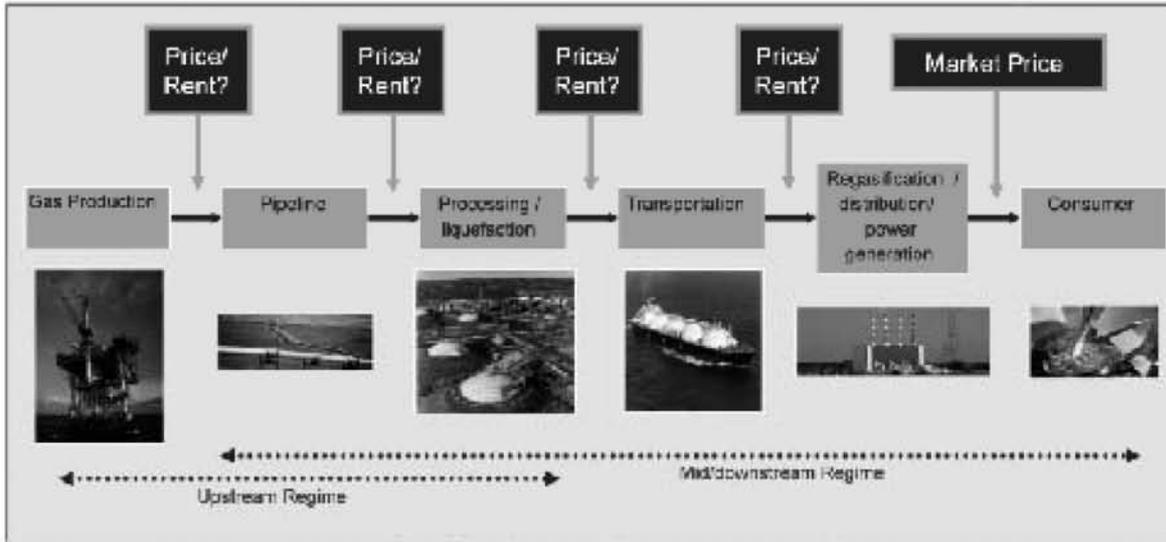


Figure 6.4 Natural gas value chain.

Note

Number of links in each chain depends on the project (e.g. gas may be sold directly to consumer after processing).

- be sent by pipeline to a processing plant or direct to the end user;
- be processed, which will likely include extraction of associated liquids and may also include liquefaction of the gas itself within an LNG or gas to liquids (GTL) project;
- be sent on to the market, either as dry gas to the end user or for secondary processing (e.g. power generation) or as liquids;
- be converted into the end product (e.g. electricity) or back into dry gas, if in liquid form (i.e. regasified); and
- finally, be sold to the end user.

The final market for the gas may be domestic, which is likely to have prices regulated by the government, or abroad. Fiscal policies and terms need to address all of these possibilities as the gas industry in any country may encompass the whole spectrum of gas utilisation projects and ownership combinations.

The owners of each link in the chain incur significant costs and expect to recover these costs, plus a share of the economic rent generated. Economic rent is defined as the product sale price less the costs of production, transportation and distribution, including a minimum return on capital employed, over the full cycle (i.e. lifetime) of a project. Each link also has to balance the inherent risks involved with the potential rewards. While the ultimate price may fluctuate, affecting all links of the chain, upstream producers encounter the most risks, including geological (exploration), reservoir and technology risks and will usually seek a proportionally higher share of the rewards as a result.

Depending on their attitude to market risks, the owners of any of the links in the chain may try and either protect or expose their operation to prevailing

market prices. Risk-averse owners may charge a fixed fee (e.g. feedgas price, pipeline or plant processing tariff) while risk takers will seek as much of the final price as possible. Normally, the more risk-averse owners will accept a lower share of the overall economic rent generated in exchange for 'downside' protection.

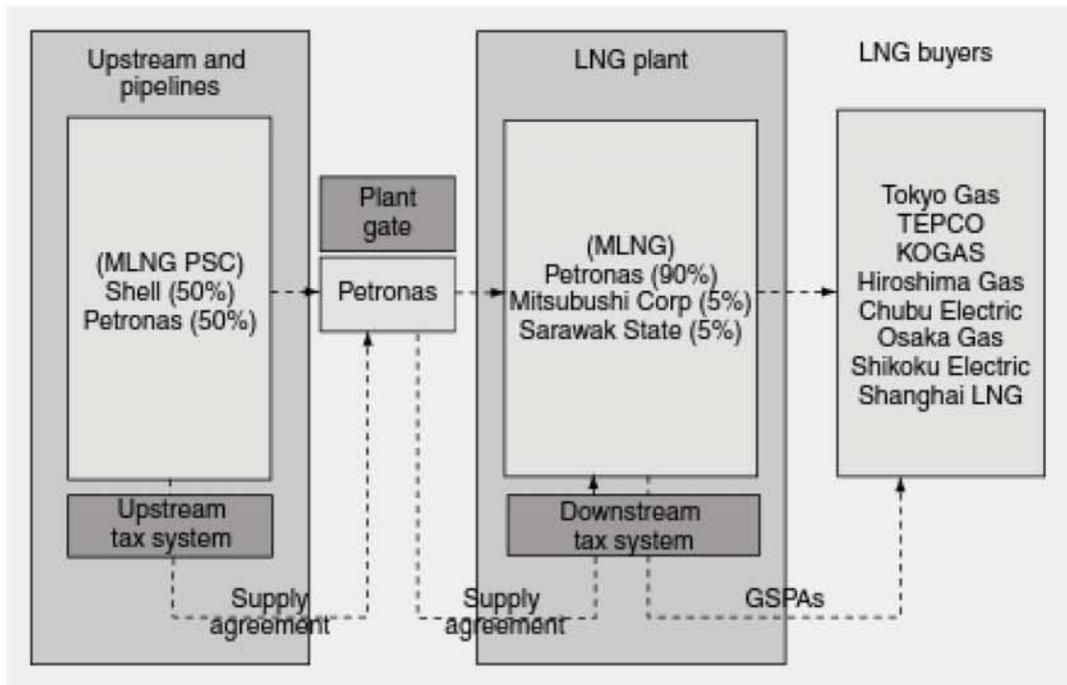
Where the owners of each link are different, pricing agreements between links should be transparent and 'arm's length', although the complex, global relationships between buyers and sellers has raised the question of whether any transaction is truly 'arm's length'; this issue is discussed elsewhere in this volume. Where the owners of different links are the same and there is clearly no arm's length sale, then transfer and reference prices need to be established for fiscal purposes. These should reflect the different risks being assumed by the different links and prevailing market conditions. The alternative is to create a unique fiscal regime for the entire 'integrated' project.

In countries where gas industry infrastructure is not well developed and/or the gas project is particularly large, gas producers will often seek to have an economic interest in the full chain and participate in the ownership of the pipelines, processing facilities and transportation. They may even seek to buy the gas themselves for re-sale in another country. The main driver for this is normally control of the entire project, but it can also be driven by a desire to ensure that the company participates in any link of the chain which is generating the most economic rent. Most integrated projects are LNG export schemes but integrated domestic projects also exist, notably independent power projects (IPP), where gas producers own and operate the power generation plant and sell electricity into the local market.

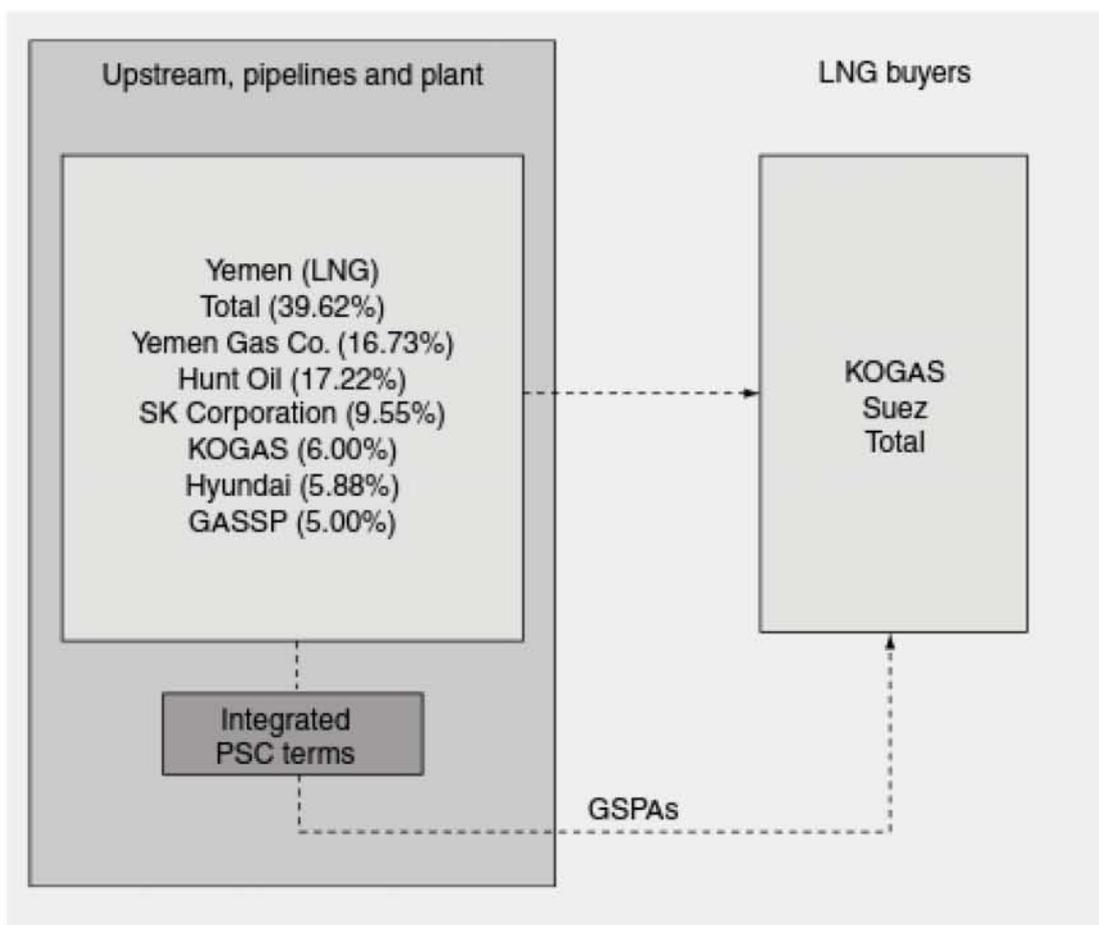
If the ownership of links in the chain is different, it is regarded as 'segmented'. The upstream links tend to include production and transport of the gas to the processing plant. Variations include producers which sell the gas at the wellhead and gas fields which include gas processing in the production facilities. Midstream links tend to include the initial and secondary processing and transportation to the end user. Gas producers will sell their production either to a pipeline owner or processing plant, which then sells on to the next link, until reaching the end user. (See Figure 6.5 for examples of segmented and integrated LNG projects.)

In a segmented chain, negotiated agreements will usually dictate the market price and level of economic rent achieved in each link. North America, the UK and a small number of emerging markets in other consuming countries have established 'spot' markets where significant volumes are openly bought and sold and prices fluctuate on a daily basis. Elsewhere, natural gas is commonly sold under long-term contracts, with producers and midstream suppliers committing to supply certain volumes to buyers over a 20-year period for a price which will often be indexed to movements in competing energy products, such as fuel oil or coal.

Most sales contracts will include clauses designed to protect both the buyer (from upstream risks) and the seller (from market risks). Producers will commit to supplying a base volume in any period, often with a 'swing' factor, enabling the buyer to take significantly more in periods of high demand. In return, the



(a)



(b)

Figure 6.5 Schematic examples of segmented and integrated LNG projects: (a) Segmented taxation: Malaysian LNG; (b) Integrated taxation: Yemen LNG (source: Wood Mackenzie's LNG service).

buyers will commit to 'take or pay', which forces the buyer to pay for the base volumes even in periods of low demand. The pricing formula will also normally include provisions for fluctuations in the final market prices, substitute fuels (such as fuel oil and coal), currency exchange rates and other inflation measures. In many LNG contracts, price 'floors' and 'ceilings' are also agreed. Prevailing market conditions and resulting bargaining power, will heavily influence the final terms agreed in any gas sales agreement.

The government may own one or more links of the chain and dictate the level of economic rent to be captured by those links. For example, Algeria and Oman insist that most of the gas produced in the country, associated¹ with oil, is taken by the government which reimburses only the producers' costs. By contrast, the Indonesian government owns several LNG plants, which it operates on a tolling basis, recovering its own costs but enabling the remainder of the LNG price received to be passed to producers.

3 Natural gas taxation

A Upstream vs midstream taxation

The fiscal regimes for upstream and midstream operations are very different in most producing countries. Upstream production tends to be subject to more complex fiscal terms and can include bonuses, royalty, production sharing and windfall profits taxes, as well as corporate/petroleum income tax. Midstream operations, on the other hand, tend to be treated as general industrial projects and are subject only to standard corporate income tax. Major projects, such as green-field LNG plants, may even receive fiscal incentives such as temporary tax holidays.

The Malaysian LNG (MLNG) project highlights the differences between midstream and upstream taxation policies and the implications for other government policies, such as gas pricing and equity participation. Figure 6.6 illustrates the

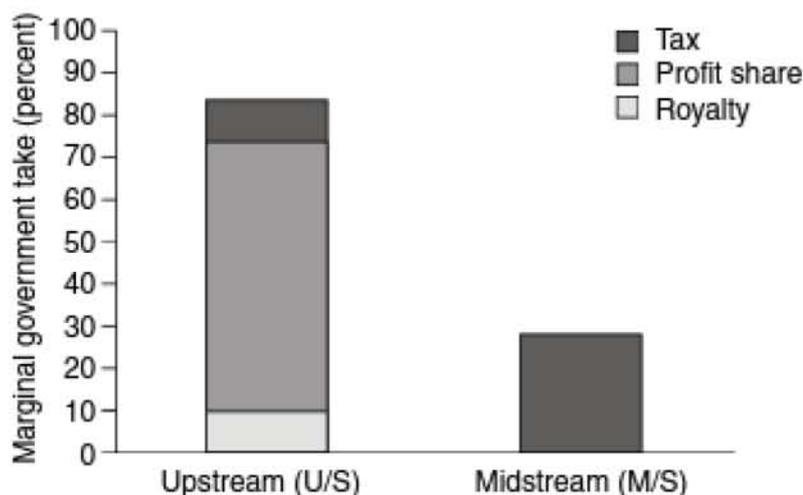


Figure 6.6 Upstream vs midstream taxation (Malaysia LNG) (source: Wood Mackenzie).

significant difference in the government take¹ from Malaysian upstream and midstream operations, where the total fiscal take is 83 per cent of upstream profits but only 28 per cent of midstream profits.

Petronas, the Malaysian national oil company (NOC), has a 50:50 joint venture with Shell in the upstream MLNG PSC. Petronas is also the purchaser of the gas at the plant gate, where it then sells the gas on to the LNG plant owners (at the same price as it pays for the gas). The price at the plant gate is usually referred to as the 'gas transfer price'. Petronas owns 90 per cent of the plant, which sells LNG to markets in North Asia.

The relationship between fiscal and gas pricing policies is critical. Figure 6.7 illustrates the difference between the total government take and investor profits from the project, under three different transfer pricing policies:

- Transfer price is established at the maximum price the midstream can pay (i.e. the plant's breakeven price).
- Transfer price is established at the minimum price the upstream can receive (i.e. the producer's breakeven price).
- Transfer price is established at the midpoint between upstream and midstream breakeven prices.

Figure 6.7 shows the distribution of the project's total profit, i.e. LNG price less the upstream and midstream costs.

The 'midstream breakeven' policy (which is comparable to the Indonesian policy of only reimbursing the LNG plant's costs) ensures that the upstream transfer/netback price is as high as possible. Figure 6.7 shows that, under these assumptions, this policy generates the highest level of overall government take because of the higher fiscal take from upstream operations.

The 'upstream breakeven' policy, which results in all of the economic rent residing in the midstream operation, is far less common. It is comparable to the

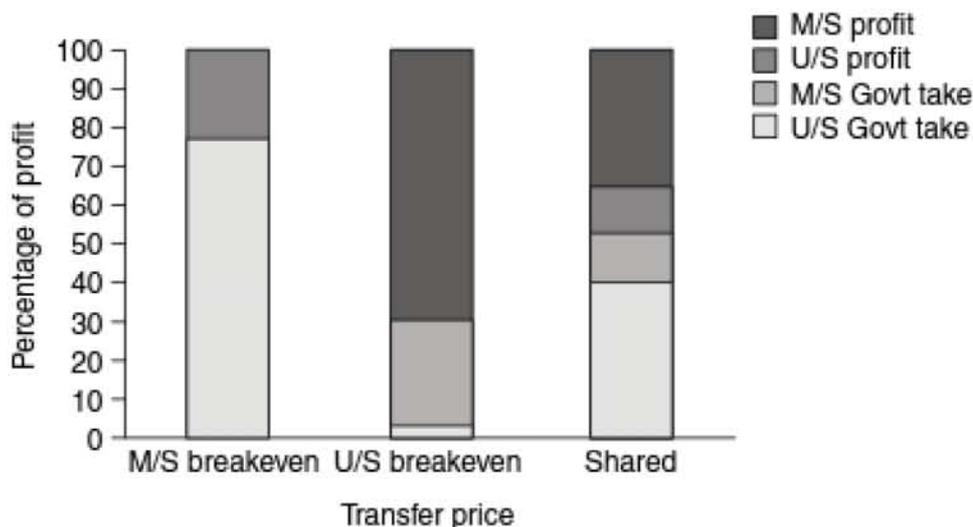


Figure 6.7 Total government take under different transfer pricing policies (source: Wood Mackenzie).

situation where upstream producers are deemed to have no rights to gas associated with oil production and deliver the gas to the government or midstream plant, with only costs reimbursed (e.g. Oman LNG) or recovered from oil revenues (e.g. Angola LNG). As a result of the lower tax rates applicable to the midstream operation, this generates the lowest overall government take of the different options.

The third alternative is that the difference between the two breakeven prices is shared between the upstream and midstream operations, either as a result of negotiation between the two parties or by government regulation. This results in a government take from the total project somewhere between the two extremes.

An example of this system is Australia's residual price mechanism (RPM), which is established for integrated LNG projects. (See Figure 6.8.) Australia levies a Petroleum Resource Rent Tax (PRRT) on upstream profits, but not on midstream operations. If there is no arm's-length agreement between the two operations, or a comparable local benchmark or price formula agreed in advance with government, then a proxy gas transfer price (GTP) needs to be established for purposes of calculating the PRRT payable by the upstream operation. Under the RPM, two prices are established:

- Cost-plus price.
- Netback price.

The RPM involves taking the average of the gap (or economic rent) between the cost-plus and netback prices for that operation. The cost-plus price represents the lowest price the upstream phase of a gas to liquids operation would sell its sales gas for; that is, the lowest price at which that operation would fully recover its costs of producing the sales gas. A gas transfer price below the cost-plus price means that it would be uneconomic to produce sales gas.

The netback price represents the highest price the midstream phase of a gas to liquids operation would pay for sales gas; that is, the highest price the operation

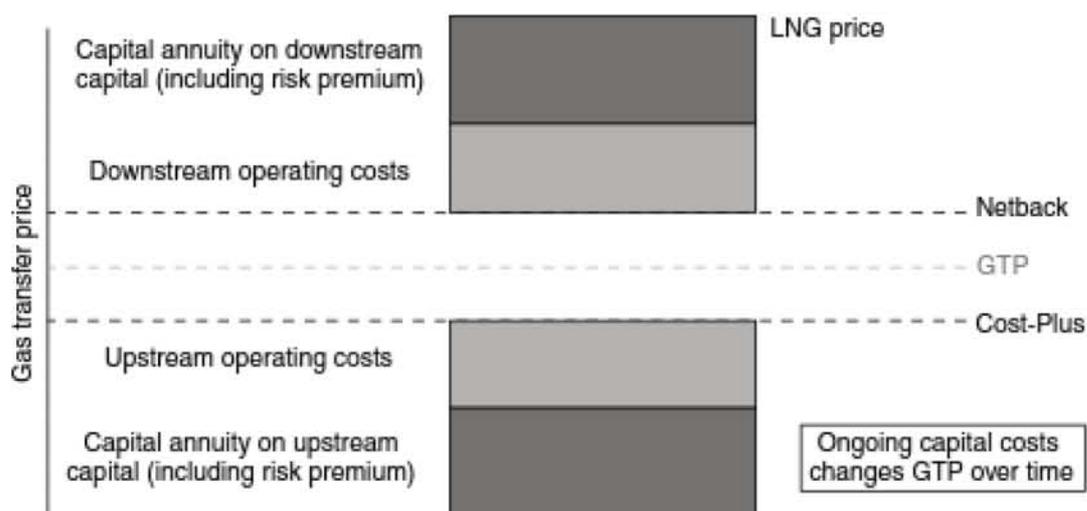


Figure 6.8 Australia's residual price methodology to establish transfer prices in LNG projects (source: Australian Government (Department of Resources, Energy and Tourism)).

could pay for sales gas and fully recover its costs of using the sales gas to produce LNG from the proceeds the operation obtains from selling LNG in the market place. A gas transfer price above the netback price means that it would be uneconomic to produce LNG.

In the cost-plus and netback calculations, capital costs incurred in the project pre-first gas are augmented using a capital allowance. Capital costs are uplifted by the long-term bond-rate plus a 'risk premium' of 7 per cent.

A feature of the RPM is that the transfer price tends to rise throughout the life of the project – a function of greater ongoing capital expenditure in the upstream phase of the project. This has the effect of gradually shifting more of the revenue to the upstream (higher tax) phase, and steadily increases the overall tax burden on the project.

As a general rule, therefore, the government will prefer to see the upstream transfer price as high as possible, when the upstream fiscal take is higher than from midstream operations. However, the government's equity interest in the chain's links can alter this perception. In the Malaysian LNG project example, the overall country take – i.e. the government take plus the NOC's equity interest – can be calculated and compared with the other companies' profit under the different pricing policies.

Figure 6.9 shows that the very high equity interest in the lower-taxed midstream operation results in a higher overall 'country take' when the lowest upstream transfer price is used than when the upstream transfer price is highest. As long as the government regards fiscal revenue and the NOC profits as similar sources of revenue, its attitude to transfer pricing can, therefore, be completely changed as a result of the difference in the NOC equity interest in the different links of the chain. Issues arise, however, when the NOC's profits begin to be diverted away from government coffers – for example, in the expansion of international investments or in dividend payments following part-privatisation.

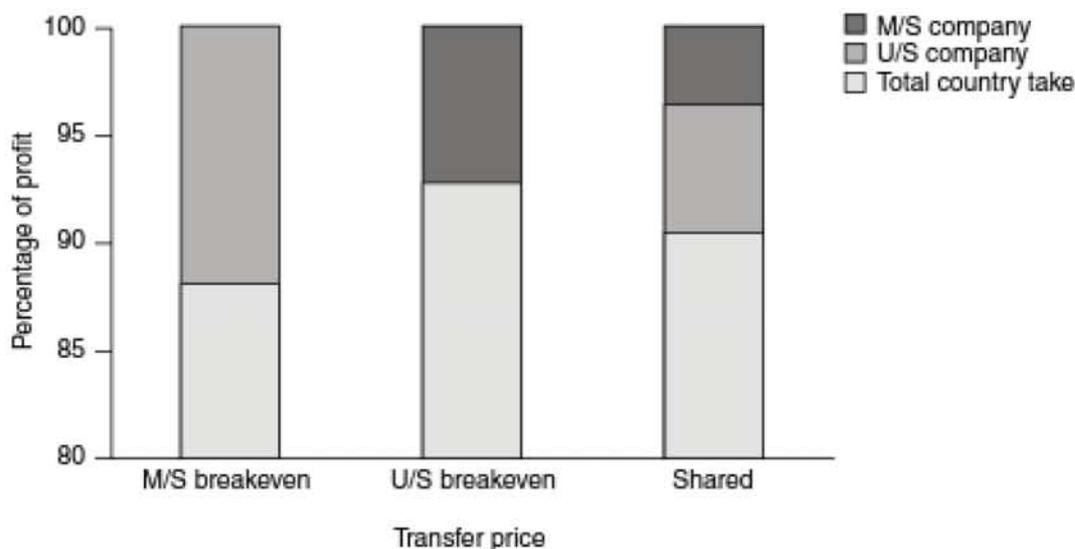


Figure 6.9 Total country take under different transfer pricing policies (source: Wood Mackenzie).

Thus, three policies relating to segmented natural gas projects need to be developed simultaneously:

- i Transfer pricing.
- ii NOC equity in different links in the chain.
- iii Upstream and midstream fiscal terms.

One route to resolving these simultaneous issues is to integrate the upstream and midstream operations into a single project with a specific fiscal regime. The NOC can take an equity interest in the entire project and there would be no need for an upstream transfer price as all fiscal considerations will be based on the final price received and all costs will be considered together.

B Integrated projects

Only projects which have a fiscal 'ring fence' around the entire project are truly integrated. If different tax systems apply to upstream and midstream, then, even with common ownership, the project is really 'segmented'. The existence of well-established upstream and midstream fiscal systems is one of the main stumbling blocks to integrating gas projects, as a new fiscal regime to apply only to the integrated project will need to overcome significant administrative and legal obstacles.

Another issue is that the gas supply needs to be dedicated wholly from fields or licence areas which are owned by the midstream participants. As soon as there is a divergence between the interests of the gas suppliers and the midstream operations, then transfer prices – and fiscal ring fences – need to be established, as discussed above. And one of the main attractions of integrated projects for government is the removal of concern about fair transfer prices being established.

Despite the difficulties inherent in establishing integrated projects, there are some notable examples:

- *RasGas LNG (Qatar)*. The development of North Field gas is subject to a consolidated royalty/tax regime, based on the entire project revenues and costs.
- *Yemen LNG*. All gas comes from the Block 18 PSC area and the PSC terms apply to gas production, valued at the Free on Board: (i.e. buyer pays for transportation (FoB)) LNG price with upstream and midstream costs included in cost recovery.
- *Snøhvit LNG (Norway)*. Uniquely for Norway, all onshore (midstream) and offshore (upstream) operations in the Snøhvit project are treated as part of an offshore project and liable to offshore taxation, which allows all offshore operations to be consolidated for tax purposes. Onshore operations are only liable to a 28 per cent corporate tax while offshore operations are subject to an additional 50 per cent 'special tax'. Investors preferred the entire Snøhvit

LNG project to be treated as offshore rather than split between upstream and midstream because they could receive immediate tax relief at an effective 78 per cent rate from oil revenue, even though all future profits would be liable to tax at the 78 per cent rate. An additional fiscal incentive granted to the project was accelerated depreciation of capital costs (three years compared to standard six years schedule). These factors highlight the importance to investors of being able to recover capital costs as rapidly as possible, as this significantly improves the rate of return.

- *North West Shelf LNG (Australia)*. Midstream costs are included in the upstream ring fence for royalty, excise and tax purposes. This is the only project offshore Australia which is liable to royalty and excise duty and not to the PRRT system described above.
- *Okpai IPP (Nigeria)*. Power generation plant capital costs are consolidated with Eni JV's oil operations and attracts tax relief at the 85 per cent oil tax rate, with upstream gas profits (which are minimal) taxed at the standard corporate tax rate of 30 per cent.

Integrating the upstream and midstream operations within the same ring fence removes the need for government to regulate and/or monitor the gas transfer price to ensure fiscal fairness, but it still needs to ensure that the final product price is also reasonable. This issue is discussed further in Section 4 'Natural gas pricing and taxation'.

C Comparison of natural gas and oil taxation

The high levels of rent associated with oil production has resulted in many fiscal regimes for oil generating a very high level of government take from oil revenues. Some governments have used the existence of highly profitable oil projects to incentivise development of less attractive gas projects, particularly associated gas.² Gas which cannot be produced commercially must either be re-injected or flared. If the quantities of gas are large, re-injection can only be a temporary solution and gas flaring is universally discouraged (even if it still continues in some old facilities). Investors and government keen to progress development of oil then need to seek alternative solutions for the simultaneous development of the gas. Some examples of the resolution of this apparent stalemate can be found in:

- Nigeria: oil producers are currently allowed to include costs associated with the development of gas facilities in the capital cost pool for oil tax purposes and, therefore, receive tax relief at the Petroleum Profits Tax (PPT) rate of 85 per cent. Any operating profit from the gas sales (i.e. revenue less operating costs) is only liable to standard corporate income tax at 30 per cent. This enables producers to accept much lower gas prices than would be possible if the gas capital costs were not consolidated with oil.
- Angola: the NOC receives associated gas from certain deep water oil developments free of charge at the beach. In return the oil producers are allowed

to include the costs of the gas pipeline in their cost recovery pool, which attracts an uplift allowance and is included in the IRR-based oil production-sharing calculation, thus reducing the government's share of the oil profits.

- Algeria: in some projects, the investor is entitled to a share of the proceeds from sales of condensate and other associated liquids to recover costs and make a return, but all of the separated gas production is taken by the national oil company, Sonatrach.

Governments also often compensate for the less attractive economics of gas projects (see Section 3D 'Petroleum economics') by offering more attractive fiscal terms to gas producers, compared to oil. These can take several forms, but the most common are:

- lower royalty rates (e.g. Nigeria, Tunisia, Vietnam);
- higher cost-recovery ceilings and/or profit shares (e.g. Egypt, Indonesia, Malaysia);
- lower tax rates (e.g. Nigeria, Tunisia, Papua New Guinea); and
- exemption from certain oil taxes (e.g. Trinidad and Tobago (Supplementary Petroleum Tax)).

Just as gas can be a by-product of oil production, liquids may also be present in gas production streams (i.e. condensate or natural gas liquids (NGLs)). If the fiscal terms for oil and gas are differentiated, the treatment of condensate and other liquids produced in association with gas is an important issue for policy makers. On one hand, as condensate tends to command prices comparable to oil, it is logical for these revenues to be treated as oil revenue and subject to the same fiscal terms as oil. This is the practice followed in most countries.

On the other hand, treating the liquids revenue as gas revenue and subjecting these revenues to lower tax rates can significantly increase the economic viability of a gas project and enable the 'breakeven' gas price required to be much lower than if there were no associated liquids. If a very high level of tax is levied on the liquids revenue, however, this economic advantage is eroded for investors. This issue is most complex when the gas production is associated with oil production. With facilities already established for the export of oil, it makes sense to separate any liquids associated with gas production in the upstream facilities and export these using the oil infrastructure. It is then more difficult for investors to argue for preferential fiscal treatment for the condensate revenues.

The application of differentiated fiscal terms when oil and gas are produced together requires costs to be allocated to the different revenue streams. Many costs, particularly operating and maintenance costs, will be common to both operations and impossible to identify as pertaining to one or the other. In these situations, some form of cost allocation is required, which can be problematic and open to possible manipulation by investors to minimise the fiscal take. The most common approach is to allocate shared costs each year according to the

proportion of total revenue generated by the project which is attributable to the different production streams.

In the few areas where domestic gas prices are not regulated and gas is sold in spot markets – primarily North America and the UK – fewer (if any) fiscal incentives are offered and the same fiscal regime applies to oil and gas production equally. This can create problems for investors if a significant divergence between oil and gas prices emerges in the spot markets. In a rising oil price environment, upstream costs tend to increase and most of these costs (e.g. drilling rig rates and fabrication rates for pipelines and production facilities) are the same for both gas and oil operations. But if gas prices do not rise as fast as oil, gas project economics will suffer in comparison.

There are a number of countries where fiscal terms have been agreed with investors for exploration and production of oil but contain no commercial terms for gas, such as many PSCs in West Africa. Investors who discover commercial quantities of gas may find that the government regards them as having no rights to the gas at all, and their involvement in the gas development will need to be gained, potentially in competition with other potential investors. In other situations, the oil investor may have the right to develop appropriate commercial terms with the government, but often the contract is silent as to the principles this should be based on.

Finally, an approach which can overcome many of the issues surrounding oil versus gas taxation is to develop fiscal terms which are linked to project profitability, such as profit sharing or tax rates linked to rate of return or 'R-factor' measures. These 'progressive' terms can apply to any individual project and will generate a high government take only from the most profitable projects. The arguments for and against the use of such fiscal regimes are made in more detail elsewhere in this volume.

D Petroleum economics: gas is not oil!

Upstream gas project economics are typically much less robust than oil for a number of reasons. First, consumers rarely pay the same for natural gas as the 'oil equivalent' price – primarily because oil production can be transported to energy markets more easily and is therefore in greater demand. Although some recent LNG purchases in Asia have been almost on a parity with oil prices and European and North American spot prices have occasionally resulted in parity pricing, normally gas prices are lower than the oil equivalent. Regulated prices in the domestic markets of developing countries will also tend to result in lower prices than for oil. Gas producers supplying export markets normally receive lower prices than oil, because of the additional liquefaction, transport and re-gasification costs. This is illustrated in Figure 6.10.

Given an FoB oil price of US\$100/bbl (3Q 2008), the energy equivalent gas price is US\$16.7/mmbtu (million British Thermal Units) (based on a bbl:mmbtu ratio of 1:6). However, FoB LNG prices will almost always be lower than this. Although some recent LNG sales agreements include parity

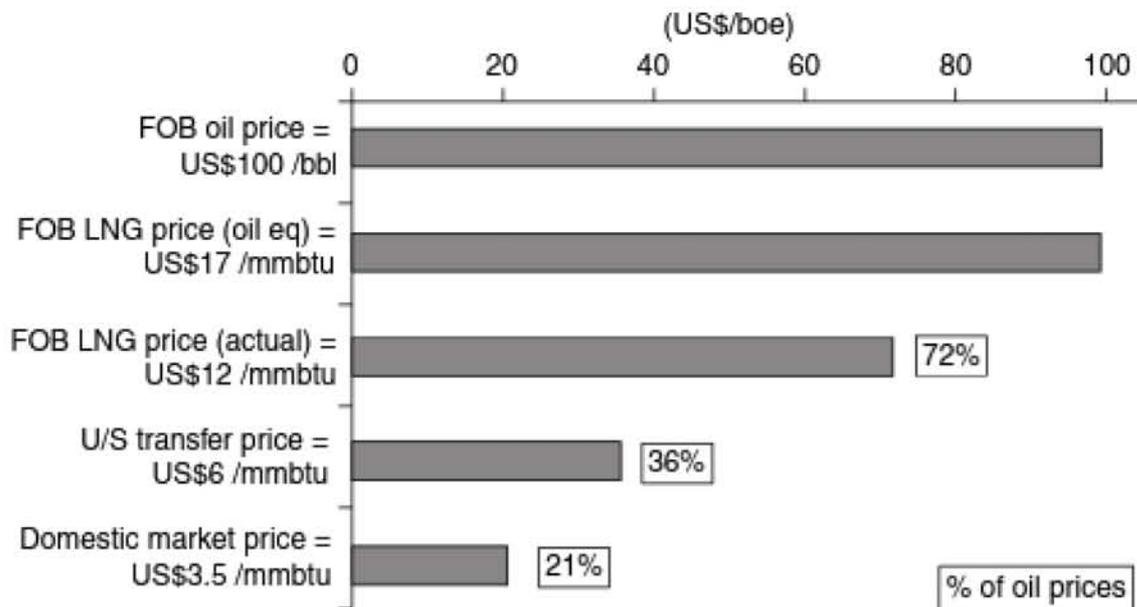


Figure 6.10 Oil vs gas prices (source: Wood Mackenzie).

Note

Numbers are hypothetical for illustrative purposes but based on some real LNG and domestic gas sales when oil was trading at US\$100/bbl.

with oil prices for delivered LNG, there is still a discount for transportation to the market and re-gasification. Most existing sales contracts do not offer parity with oil, however, and for the purposes of this illustration, an indicative FoB LNG of US\$12/mmbtu has been assumed – a 28 per cent discount on the oil equivalent price.

Before the producer receives its price, the midstream operation needs to recover its costs and make a return. Based on a US\$12/mmbtu LNG price and assuming half of the price is passed upstream, the upstream gas price is US\$6/mmbtu. This represents a 64 per cent discount to the oil equivalent price for the producer. Domestic sales prices in many developing countries are currently (3Q 2008) much lower than this. An indicative domestic price of US\$3.5/mmbtu represents only 21 per cent of the oil equivalent price.

Gas is also more difficult to transport and generally incurs higher costs. However, even if gas production were sold at parity with oil and the costs were the same on an equivalent basis, gas project economics would still likely be less attractive than oil. This is because gas in most parts of the world is sold under long-term contracts, which imposes long, flat production profiles that reduce the present value of the production.

Figure 6.11 illustrates the difference in typical production profiles between oil and gas projects with the same reserves (100 million boe). Whereas the gas is produced over 20 years, the oil field would normally be depleted much faster, with a higher proportion of reserves produced in the early years. This has a significant impact on the present value of the production. In the example, discounting future production at 10 per cent p.a. provides a ‘present value’ of 73 per cent for the oil field but only 47 per cent for gas. In other words, even if prices and costs

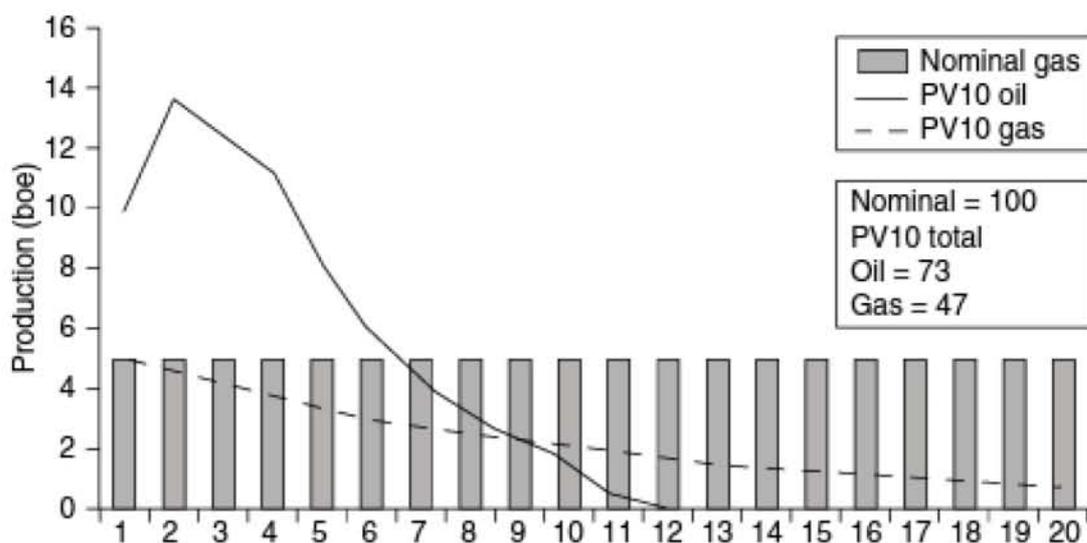


Figure 6.11 Oil field vs gas field production profiles (source: Wood Mackenzie).

are identical on an energy equivalent basis, gas production can be a third less valuable than oil production – unless the gas can be sold on spot markets and depleted as quickly as oil.

4 Natural gas pricing and taxation

A Final market and export prices

A major challenge for governments in the taxation of export projects is ensuring that the price which is used for calculating the government take is a fair and reasonable one. The lack of other gas sales prices to benchmark against and the level of tariffs charged by the owners of the links in the chain between the export point and the price paid for the gas in the final market, makes this difficult.

In an LNG project, for example, the FoB price is commonly used for calculating tax in the midstream or integrated projects. This is supposed to be the price paid by the end user, net of deductions for the transportation, regasification and marketing of the gas. Both the final market price and the level of deductions significantly impacts the FoB value, so government has a strong motive to ensure that all of these are fair. This creates difficult challenges.

The first issue is establishing that the final market price compares with similar sales by other producers into similar markets. Most gas export sales are under long-term (20–30 years) contracts, and the terms of sales agreements reflect numerous factors. The gas price in any period is normally derived from a base price agreed at the time of signing the contract and reflective of markets at the time, then linked by formulae which refer to the prevailing prices of competing fuels, inflation and other indices. Price floors and ceilings are often included.

Shifts in bargaining power and market conditions over time mean that the price being paid for gas under one agreement may be significantly different from

that under another. These prices are also only rarely reported, so it is difficult to ascertain if the price in any particular contract is significantly higher or lower than is being paid for gas from other sources. In these situations, governments can refer to the few published gas prices that exist, with the most well known being the Henry Hub spot price in the US. In Europe, the most established spot price index is the National Balancing Point (NBP) in the UK.

Where the final destination is expected to be a market which does have reported gas prices, the sales agreement will often take the reported price as the basis for the FoB price, less deductions and any additional indexation factors. Thus, sales to the US could reference Henry Hub, with the FoB price increasing or decreasing as that price changes. The more directly the sales price is associated with a widely reported spot price, the more transparent the agreement can be seen to be and the more likely it is that the FoB price is fair.

The government of the producing country should also be concerned with the level of deductions being made from the final price to cover the costs of getting the gas to the market. An FOB price derived from the final market in the US, for example, might be expressed as follows:

FoB Price = Henry Hub Price \times (100 – (A + B + C))% – (X + Y + Z), where

- A = volumes lost in liquefaction process.
- B = volumes lost in regasification process.
- C = volumes lost in pipeline to Henry Hub/market.
- X = shipping tariff from export point to receiving terminal.
- Y = tariff for regasification.
- Z = pipeline tariff from regasification plant to Henry Hub/market.

An array of factors influence the levels of tariffs which are charged by the owners of the shipping, regasification and pipeline links in the chain. These include the availability of alternative suppliers of the services and facilities, distances involved, operating and capital costs of the facilities and the rates of return included in the owners' tariff calculations (which may be regulated but normally are not).

The same companies may own more than one of these links and have an interest in moving economic rent to the lowest-taxed link. Thus, government needs to carefully monitor and benchmark each of the tariffs being deducted from the final sales price. Although this can be very difficult – and investors clearly have advantages of asymmetry of information – there is an increasing amount of data and methodologies in the public domain which can help establish benchmarks. For example, third-party tanker freight rates are publicly quoted and several pipeline companies publish existing tariff rates on their websites.

Guidelines for 'reasonable' rates of return to be included in gas processing and pipeline tariffs are established under the US Federal Energy Regulatory Commission (FERC: www.ferc.gov) and Canada's National Energy Board (NEB: www.neb.gc.ca) rulings. It remains true, however, that ensuring fees

charged for handling and processing gas (outside of the producing government's jurisdiction) are fair and reasonable is a significant problem for many governments. One possible solution to this is to place the 'burden of proof' onto the producing company in a self-assessment of the FoB price received. Under this policy, the company would need to demonstrate to the government that the fees it was paying (and volume losses it incurs) are within a reasonable range for the relevant cargoes.

A final issue related to netback pricing which has emerged in recent years is that the agreed FoB price may not actually reflect the final realised price. Some companies have developed integrated LNG businesses and can make use of their presence in different markets to optimise the economic benefit from any LNG trade. For example, an LNG buyer could agree to pick up LNG cargoes from a producing country, with an agreed price formula linked to the prevailing Henry Hub gas price, with the intention that the cargoes will be sold into the US market. However, if the buyer has an opportunity to sell the cargo into a different market (e.g. Asia), then it can do so and benefit from the price upside. The producing government (and producing company) will receive none of the upside unless the LNG sales agreement specifically addresses the issue. As a result, producers are beginning to seek specific sharing mechanisms for additional price upside in new LNG agreements.

B 'In-country' costs

The issue of fair and reasonable fees charged is also pertinent to links in the value chain within the country. Fees will be charged by infrastructure owners (IOs) to third parties (e.g. producers of small gas satellite fields (SPs)) for use of gas gathering, processing and transportation facilities. Some transport facilities – primarily major gas pipelines in North America – are owned by companies which have no economic interest in the producing fields, but it is common for the development of natural gas infrastructure to be included as part of a first phase of upstream gas field development. Tariff agreements for the use of these facilities are normally the result of commercial negotiations between the IO and SP and rates will be negotiated somewhere between the IO's incremental cost of providing the service (which may be near to zero) and the SP's opportunity cost of developing an alternative option to deliver its output to market (which would often render the development uneconomic).

In the early years of an emerging basin, the major infrastructure will normally be owned by the producers of the initial field developments and their production will use most, if not all, of the available capacity. In these circumstances the IOs can essentially offer 'take it or leave it' terms to SPs. As basins mature and the number of pipelines and other alternative routes to market increase, the SP should develop a stronger bargaining position. As production from older fields decline and capacity becomes available in processing facilities and pipelines the IO will normally be keen to share the ongoing operating costs with SPs and tariff terms will become more favourable.

Tariff agreements are expected to arise from negotiations but, to different degrees, governments retain the right to intervene if an SP complains about the rates being offered by the IO. Canada and the US have regulatory bodies which oversee tariff settlements and provide guidelines for industry to follow. In the UK the industry and government have jointly developed guidelines for infrastructure access. In Norway and several developing economies with well developed national oil companies, all gas pipelines are operated by the state and pipeline tariffs are established by government.

Processing and transportation tariff arrangements are normally based on an SP securing a certain amount of capacity, often with an additional element based on actual throughput. This may be modified by 'use or pay' terms, which oblige the SP to pay a fee on the basis of a certain amount of throughput, regardless of how much production is actually sent to the facilities. Additionally, the SP may seek 'firm', i.e. guaranteed, or 'interruptible' access to the facilities, with lower tariff rates for the latter arrangement. Both parties will assess the risks of capacity and production volumes being available when negotiating the terms. Other agreements will provide for an 'all in' single rate, but in most cases the actual rate agreed will normally be calculated with some reference to the IO's operating and capital costs.

The 'operating fee' is normally established to share the ongoing operating costs of the infrastructure, according to each party's share of total throughput. The 'capital charge' is supposed to enable the IO to recover costs and make a return on equity/capital employed, and agreement on what is a reasonable return is one of the most likely sources of breakdown in negotiations between the parties. Some governments have issued guidelines on what is regarded as a 'reasonable' return on equity. IOs are not obliged to use these in negotiations, but if a case goes in front of the regulatory body, a significant departure from the return rate (without good cause) could be deemed unsupportable.

Fiscal terms can influence tariffs sought by IOs and the tariffs can impact fiscal revenues. Third party tariff income is normally either taxable or reduces tax allowances, which means that IOs seeking a net income must build the effective tax rate into their calculations. Where IOs are subject to different royalty or tax rates, this can create a competitive advantage for the IO with the lower tax rate as it can charge a lower fee to generate the same net after-tax income.

Similarly, because of the deductibility of tariffs, governments need to ensure that the tariffs charged are not being manipulated to achieve tax minimisation. The opportunity for this will be most apparent when the IO and SP have different tax rates and if a company has an economic interest in both the IO and SP.

C Subsidised prices or fiscal revenues?

In most developing countries, domestic energy prices are regulated and the resulting low prices available make these projects relatively unattractive to producers. In many countries, the inability of local consumers to pay anything like the international market prices for gas has traditionally meant that developing gas for domestic use has been considered uneconomic by investors, who are

mostly interested in exporting gas to the more lucrative markets in North America, Europe, Japan and Korea.

The increase in energy prices between 2002 and mid 2008 has slowly been reflected in increasing domestic prices in developing countries, and interest in local projects is growing among producers, not least because of the surge in costs associated with exporting gas, whether by long-distance pipeline or LNG. With a strong political desire in most countries to expand local gas utilisation, the more the economic differential between domestic and export sales is reduced, the more attractive local projects will become. However, the transition from the current price structure in most developing countries to one comparable to that prevailing in the main consumer countries will take time.

In the meantime, to encourage development of gas supplies for domestic utilisation, governments are beginning to require gas producers pursuing export projects to include a component of domestic gas utilisation. For example, a new LNG project may require producers to also provide feedstock to a local power plant, as part of the overall development. Without the domestic commitment, the export project will not be approved. Thus, producers are obliged to supply the local market, although they will tend to keep their involvement in supplying gas to buyers as far upstream as possible.

Where prices are below the costs of production, the only way investors can be persuaded to develop the gas is if the government provides a subsidy – either explicitly or implicitly through some form of consolidation with oil production. Nigeria, for example, got around a similar economic impasse by allowing oil producers to consolidate the capital costs of gas utilisation projects to be recovered from oil revenues, thus attracting 85 per cent tax relief, while allowing any operating profits to be taxed under standard corporate tax rules, at a 30 per cent rate. Under certain circumstances, the tax generated from the production would be less than the tax relief allowed up front – an implicit subsidy for the oil producers. Investors claim that without this fiscal incentive, local gas prices – including the feedgas price the Nigerian LNG ('NLNG') project pays – are not high enough to enable economic development of the reserves. There has been much debate over the fiscal rules for gas projects in Nigeria in the past few years, but a new fiscal regime has yet to emerge (3Q 2008).

Where there is a significant divergence between domestic and export prices for gas, governments can either incentivise domestic projects through lower taxation or explicit subsidies to producers. Alternatively, they can reduce the economic attractiveness of export projects by levying an export duty on production. This can reduce the netback price to equate to the price available in the domestic market. There are a number of countries which impose such duties on oil exports, but only a small number apply export duties to gas, notably Argentina and Russia.

5 Conclusions

The government's pricing, NOC equity position and fiscal policies for natural gas projects must be developed simultaneously. If the existing upstream and

downstream fiscal regimes are different – which is normal – the transfer price between the upstream and midstream operations becomes crucial. Under arm's-length agreements between upstream and midstream operations, market forces should dictate an appropriate price. If ownership of the two operations is the same, however, a proxy transfer price needs to be established. Alternatively, a separate tax regime could be developed for an integrated gas project, with the combined upstream and midstream operations treated as the taxable entity.

Just as it does for oil, governments need to closely monitor and benchmark final market prices, interim transfer prices and charges in each link of the value chain to ensure that taxable income is fairly calculated. In particular, government and producers should aim to share in realised market prices which are greater than expected, and this needs to be addressed in gas sales agreements. Unlike oil, however, the availability of market data on such sales is limited and often held confidential under long-term gas sales agreements, suggesting that the 'burden of proof' should rest with the taxpayer.

A high liquids content in a natural gas project significantly enhances its profitability and can enable producers to charge a lower price for gas. This can make the difference between a gas project being economically viable or not. When the liquids are liable to a high tax rate (e.g. oil tax rates), this economic benefit can be neutralised for investors. It is, therefore, important to consider how condensate is treated under differentiated fiscal terms, as this can influence the pace of development of the gas industry.

Gas projects may require more attractive fiscal terms than oil projects as a result of lower profitability, caused by lower energy equivalent prices; higher transportation costs; and longer, flatter production profiles. Fiscal terms which are progressive and linked to project profitability could apply to both oil and gas and the level of government take will automatically be lower from less profitable projects.

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Notes

- 1 Government take = Sum of all royalties, taxes, profit share, etc., expressed as a percentage of the pre-take cash flow or NPV. Country take = Government take + NOC equity cash flow.
- 2 'Associated' gas normally refers to gas which is produced in conjunction with oil but where oil production is the primary focus of the project. 'Non-associated' gas normally refers to fields/reservoirs which contain mostly gas reserves, although associated liquids such as condensate may be present as well.