Global oil & gas tax newsletter
Views from around the world

In this issue

October 2012

Spotlight on LNG: Transfer pricing challenges in the industry

Introduction

The global liquefied natural gas ("LNG") industry is one currently enjoying a period of rapid growth. Technology advances towards the end of the last century combined with surging demand from energy-poor countries has led to an environment where previously "stranded gas" can economically and efficiently find its way to market. The LNG sector, like much of the global energy industry as a whole today, is such that practically every company will have to engage in intercompany trade to a greater or lesser extent. With that intercompany trade comes a need to determine a price which adheres to relevant transfer pricing legislation, which normally reflects how two parties acting at "arm's length" would strike a deal. A unique blend of capital investment, technology and illiquidity has allowed this industry to exist and indeed propelled its recent growth, but it is these same characteristics which often make identifying a reliable transfer price so very difficult.

This article sets out some of the unique features of the LNG industry which impact the transfer pricing policies applied by market practitioners and discusses some of the common transfer pricing issues experienced. It is important to bear in mind though that transfer pricing in the LNG industry is an evolving art and requires a specific approach for each particular situation. While the following discussion is based upon our understanding of common practice in the industry, it should be carefully considered for its applicability to a given transaction or scenario.

Overview of the industry

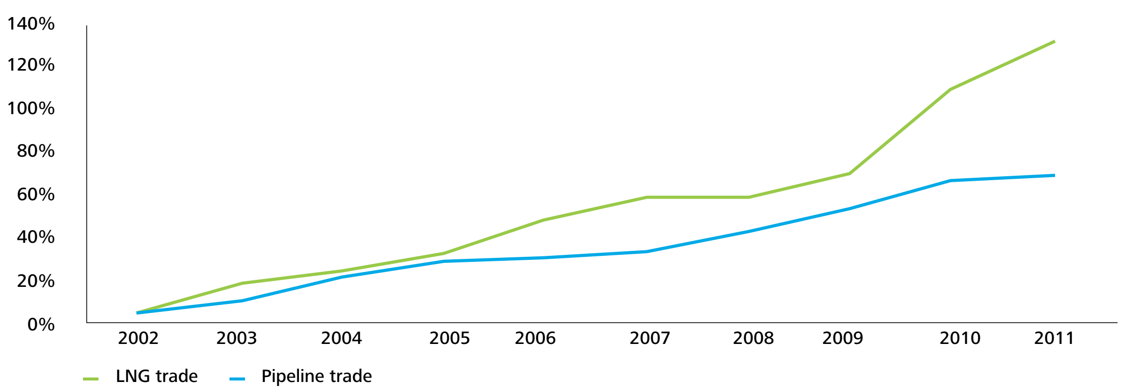
The technology to enable the liquefaction of methane on an industrial scale was first developed in the 1960s. However, the practice was slow to spread in a world which was at the time enjoying a bonanza of relatively cheap oil as its primary energy source.

A unique blend of capital investment, technology and illiquidity has allowed this industry to exist and indeed propelled its recent growth, but it is these same characteristics which often make identifying a reliable transfer price so very difficult.

In its early years, at least, LNG grew at a very leisurely pace – oil was abundant and far easier to transport and the fact that the U.S. and UK enjoyed gas self-sufficiency combined with the relative ease of piping gas into much of the rest of Europe meant that the only real area of LNG growth came in Japan. This changed in the late 1990s as the UK neared the end of self-sufficiency, price shocks impacted European gas supplies from Russia, and improvements in technology enabled the construction of "super trains" of LNG from the vast gas fields of the Middle East. The industry has been growing at breakneck speed since, as shown in the table below, which compares global growth in LNG trade and pipeline trade:

> The high cost and fact that there are a relatively small number of countries who perceive a benefit from its export … means that there are a comparatively small number of market participants ….

Percentage growth since 2001



Source: BP Statistical Review of World Energy 2002-2012

Underlying the industry's slow growth from inception is the fact that LNG is a very expensive business to operate in. Liquification and regasification plants, for a start, do not come cheap. Chevron's recently approved Wheatstone LNG plant and associated infrastructure in Australia, for example, is forecast to cost a hefty US$29 billion.[1] Regas facilities, although considerably cheaper, will still run to the hundreds of millions. Shipping too is costly, with new LNG vessels costing up to US$200 million apiece.[2]

Despite the incredibly high costs of operation, for several countries where gas resources far exceed domestic demand (such as Qatar, Russia, Australia and Malaysia) and where pipeline gas is not an option, LNG has been a fantastic boon-enabling monetization of their resource endowment. Nowhere is the discrepancy between gas reserves and domestic demand more acute than in Qatar, the world's largest LNG exporter.

A population of 1.7 million[3] people sits on gas reserves of 25 trillion cubic meters,[4] the third largest in the world. It is no surprise to see that in 2011 31% of global LNG supply flooded from this tiny emirate.[5] The high cost and fact that there are a relatively small number of countries who perceive a benefit from its export (only 19 countries export at present) means that there are a comparatively small number of market participants – a factor which, as we will see, impacts available transfer pricing approaches.

Historically, the extremely high capital costs of entering the industry led to a clear preference for long-term pricing for sales of LNG and it was usual to see term deals of 20+ years. Indeed, the financing of a project often dictates that buyers need to be lined up and contracts signed before the final investment decision is taken and construction on liquefaction plants or ships can begin.

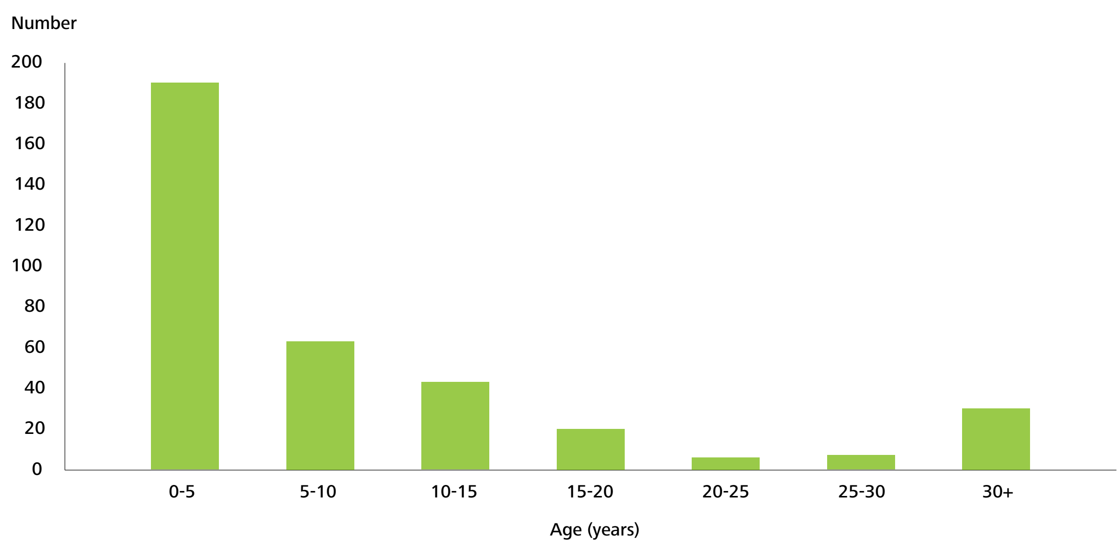
1 Chevron press release, at: http://www.chevron.com/chevron/pressreleases/article/09252011_chevrongiveswheatstoneprojectgreenlight.news
2 LNG, a liquid market – An economist special report, http://www.economist.com/node/21558456
3 Qatar Statistics Authority, http://www.qsa.gov.qa/eng/index.htm
4 BP Statistical Review 2012, available at: http://www.bp.com/sectionbodycopy.do?categoryId=7500&contentId=7068481
5 The LNG Industry in 2011, The International group of LNG Importers, http://www.giignl.org/fr/home-page/publications/

While the market is moving towards a greater flexibility of destination and more spot transactions, a clear dominance of term pricing remains. Out of the 241 million tons of LNG traded in 2011, only 61 million tons, or 25%, was bought and sold on the spot market.[6]

The comparatively small number of participants in the market, the dominance of term deals, and the absence of pipeline gas alternatives in the biggest market, Asia, has led to a market today which still exhibits a degree of illiquidity. This too is an important factor from a transfer pricing perspective. The illiquid nature of the LNG market means that structural pricing discrepancies in global gas markets, which might otherwise be eliminated through arbitrage on the LNG spot markets, are allowed to evolve. The three main global markets for LNG – the U.S., Europe and Asia – have historically all tended to be priced on different bases and exhibit slight variances but, as has been well publicized, in recent years this spread has widened dramatically – primarily as a result of shale gas keeping prices at record lows in the U.S. and, conversely, Fukushima and the lack of an acceptable nuclear power alternative pushing prices high in Asia. The small size of the LNG market in comparison to the global gas market as a whole means that it would never be possible to use LNG to arrive at perfect market parity, but many analysts believe that a liquid market in LNG might have gone some way to narrowing the gap.

Despite the high costs of entry, volatile regional pricing, and the lack of liquidity, the future of the LNG industry looks very strong.

Despite the high costs of entry, volatile regional pricing, and the lack of liquidity, the future of the LNG industry looks very strong. Most market analysts expect the growth trends shown in the graph above to continue in the near to medium term, driven by growing Asian demand and the huge increase in supply brought about by the shale gas revolution. Indeed, in an industry where the life of an LNG tanker is anything up to 50 years, and where once built it will have little option but to transport LNG, nothing perhaps demonstrates the industry's faith in itself better than the rapid recent rate of shipbuilding. The chart below shows the current age of the global LNG fleet – over 50% are less than 5 years old.



Source: The LNG Industry in 2011, The International Group of LNG Importers

6 The LNG Industry in 2011, The International group of LNG Importers, http://www.giignl.org/fr/home-page/publications/

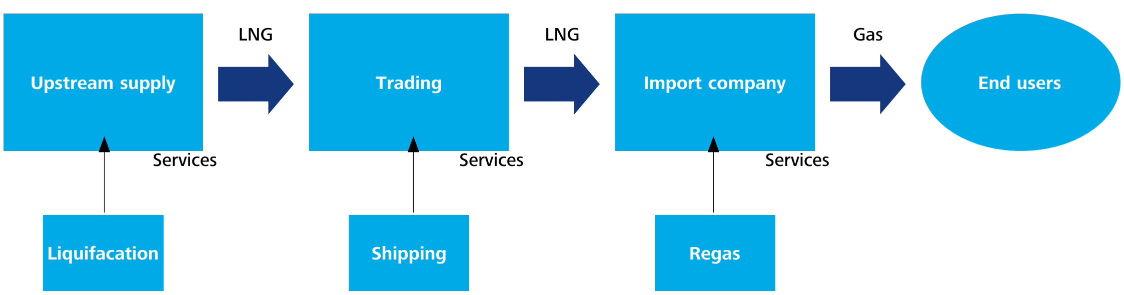
Transfer pricing in the LNG industry, like much of the energy business, often follows a "net back" principle.

Why does the industry structure lead to transfer pricing difficulties?

Transfer pricing in the LNG industry, like much of the energy business, often follows a "net back" principle. This is where a return for the multitude of intermediary activities between extraction and sale is deducted from the end sales price to arrive at the price paid at the intermediate points in the supply chain. The result is often that the bulk of the profits from a venture tend to reside with the upstream entity. This pricing structure enables national governments to obtain their share through taxation of upstream entities (or alternatively outright ownership of upstream assets) and for investors to earn a return on the high capital costs. The most common types of intercompany transaction seen are, firstly, a transfer between the upstream supply to an intermediary trader that aggregates a portfolio of different sources of supply and, second, sales by that intermediary trader to regasification facilities. However, as will be seen in this article, transfer pricing issues can also materialize across the supply chain. The diagram below sets out a simplified version of a typical LNG value chain.

A "net back" pricing mechanism was first used between Shell and Gulf Oil for the purchase of Kuwaiti crude in the late 1940s and indeed the principle works very well in the oil industry. The LNG industry is very different from the oil industry, however, and a number of issues materialize when attempting to apply the same approach. The first difficulty that presents itself often relates to "origination," however the pricing of marketing and trading and indeed the purchase and sale of cargoes of LNG all have their own unique challenges.

These differences in the manner in which the LNG market functions also need to be considered against the backdrop of a comparatively illiquid market with relatively few participants, and certainly very few sources of publicly available data. The lack of data means that the most favored transfer pricing method, the Comparable Uncontrolled Price (or "CUP") method, almost always cannot readily be applied. As we will see, this lack of direct comparable data often necessitates the application of alternative, profit based, approaches.



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Rewarding contract origination

Perhaps the most striking manner in which the global LNG industry differs from the global oil industry is in the importance of "contract origination." As discussed earlier, the long lead times and high capital costs of the industry have historically required that long-term contracts be entered into. The negotiation and agreement process for such contracts tends to be lengthy and incredibly complex. It is not unusual to see final sales and purchase agreements ("SPAs") which run into hundreds of pages. Term contracts can relate to either the sale or purchase of LNG and once signed, they will enable a supplier to be sure of obtaining an income stream from its investment or a purchaser to be sure of a supply of LNG. Depending on future market movements, they can also constitute a significant "locked in" price profit. As a result of the pricing and overall deal structure, these contracts can often be of considerable value.

The question from a transfer pricing perspective is often how to reward these skilled, value adding teams. Should these teams sit in entities different from those actually buying or selling the LNG through the relevant contracts? The value added by the origination teams is an important factor to bear in mind when assessing who should earn the bulk of the profits from the contracts originated. However, arguably more important is to assess which entity will bear the economic risk of the contracts entered into by originators. Contract risk here can be considerable – just as long-term LNG contracts can become very valuable if global gas prices move in the right direction, they can also become a millstone around a company's neck if they are priced unfavorably.

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Permanent establishment issues can also often materialize as a result of this function, which in turn present their own unique challenges. If the origination team engages in detailed negotiation with potential counterparties and perhaps signs term sheets, it is likely that this activity could constitute a form of agency activity which might give rise to a permanent establishment of the intended signatory entity in locations in which key individuals involved in deal structuring and negotiation have been based. In such circumstances, the question becomes not so much how to reward the legal entities in which the originators sit, but the appropriate means of attributing profit to any permanent establishments of the principle entity, wherever they may have been created.

Rewarding marketing

Spot cargo marketing, although in many ways similar to the origination of long-term sales deals, is subtly different. Not all LNG suppliers seek to market cargoes on the spot market, but often a need can arise because of, say, unexpected additional supply at the liquefaction plant (and hence the appearance of LNG which has no pre-scheduled destination). Functions here often involve the identification of potential spot purchasers, the agreement of master sales agreements with potential counterparties and sometimes a range of intermediary logistics services.

While many of the remuneration and permanent establishment risks remain the same as with "contract origination," the relative value added by marketing teams, and hence the reward, is often less than that for origination activities.

Rewarding regasification

The function of regasification, and to a certain extent liquefaction as well, is often set apart from the main trading and selling entities within a group within a distinct service entity. Issues regarding how to remunerate such companies often arise here – a simple operating margin is seldom appropriate given the significant capital investment which the construction of both liquefaction and regasification plants will have required. It is often the case that some form of required return on capital is factored into a formula (also including variables such as project life, capital costs, etc.) to determine an appropriate arm's length fee for the regasification or liquefaction services provided.

Rewarding trading

Trading is a distinct function from both origination and marketing. In the LNG industry trading involves an evaluation of the company's existing portfolio, an analysis of market opportunities, and an assessment as to whether profit can be made from purchases, sales, or a mixture of both on the spot market. It is often a combination of scheduling, production profiling, hedging, economic forecasting, price prediction and some limited marketing. Not all entities involved in the LNG industry will engage in portfolio trading, indeed it tends to be entities such as the banks or the super majors who have a big enough portfolio to make trading worthwhile and also who have sufficient appetite for the sizeable risk that this activity brings with it.

Trading can be a very difficult function to determine an appropriate arm's length reward for. The LNG industry is a global one in operation 24 hours a day and it is not unusual for market participants to have two or more trading "hubs" to ensure complete global coverage and that no trading opportunity is missed. A common question which follows is how to reward each "hub." In many ways trading of LNG in this manner is similar to the trading of oil (where hubs are often rewarded through use of the "profit split" mechanism) but there are some differences. The fact that the LNG market has less liquidity means that there will be a smaller pool of potential trades open to each market participant – this arguably makes it easier to assess and model potential trades but also potentially harder to generate profit (the potential deals evaluated often being the same ones being assessed by most competitors).

Trading can be a very difficult function to determine an appropriate arm's length reward for.

Trading oversight and strategic decision making thus become very important. In summary, while an appropriate starting point for rewarding a trading function may be the "profit split" principle applied in the oil industry, it is likely that some refinement may be required.

If it is the case that a trading team trades with a group's own portfolio, an interesting question arises with regard to what should be viewed as the profit from trading (as opposed to the profit from simply holding the cargoes or having access to long-term supply). Traders could not make the profits they do without access to a portfolio to trade with; hence it is often appropriate to attribute some of the profit earned to the entities which own the rights to the underlying cargoes.

Analyzing bargaining position will suggest how, acting at arm's length, the parties would be likely to split the profits ….

Pricing an LNG cargo

After rewarding any origination, marketing and trading teams, there is still a question of which entity should earn any remaining profits. In transfer pricing terms, this is often assessed with reference to the entity which bears the risk associated with the purchase and sale of the cargo and performs the associated strategic risk management functions. However, it is often the case that economic factors necessitate the transfer of an LNG cargo from one entity to another and, hence, this risk is shared. This tends to occur in two circumstances.

The first relates to "matching" supply and demand. If, for example, one group company has originated a long-term supply contract from, say, Indonesia, and a second group company has originated a long-term sales contract in India, there will clearly be a need for an intercompany transfer at some point. The question of how to price is often a very complex one – it will depend on the nature of the purchase contract, the sales contract and the value added by each party. Often the answer will be found in analyzing how much "in" or "out" of the money each contract is, although this if often very difficult given the industry's lack of liquidity and, hence, the absence of a reliable "market" price for LNG.

The second circumstance where intercompany transfers occur relates to cargo "diversions." This is where a company has an existing commitment to supply an LNG cargo at a particular destination but the group realizes that it can earn additional profit from "diverting" to an alternative destination. Continuing our example above, this could mean that the Indonesian cargo is never actually sold to the Indian related party but is diverted to, say, Japan through a third group company, as a result of a higher potential price there (with the group then meeting its Indian contractual obligation through domestic gas purchases perhaps).

Here the question of how to price becomes even more complicated. There are potentially three group companies who could claim to have an interest in the profit the group earns from the supply of that particular LNG cargo – the company with the Indonesian supply, the company with the original sales capacity in India who now has to work to fulfill that contract through alternative means and the company with the regasification capacity in Japan where the cargo eventually ends up. The picture is further complicated depending on whether title transfer between Indonesia and India occurs before another title transfer to Japan, or if there is simply one transfer from Indonesia to Japan. If we assume that the original intended profit from the Indonesia-India transaction is known through the company's "matched sale" policy discussed above, the question essentially becomes how much of the additional "diversionary" profit should be earned by the supplier (whoever that may be) and how much by the end seller in Japan.

In transfer pricing terms there are a variety of means of unpacking this puzzle. The OECD's Transfer Pricing Guidelines suggest that an analysis of relative "bargaining position" of each party might be helpful in these types of circumstances. Analyzing bargaining position will suggest how, acting at arm's length, the parties would be likely to split the profits – results of the bargaining position analysis will vary but in most instances there is a magnetism towards a 50:50 split. The seller has the cargo but the purchaser has the opportunity – they both need each other to make the envisaged profit from the venture.

Concluding comments

As we have seen above, the LNG Industry is a very complicated one. However, beneath these complexities lie opportunities – the numerous complications and peculiarities of the industry enable a variety of credible transfer pricing approaches to be put forward and the comparative infancy of some transaction types means that taxpayers may well be granted a degree of latitude in setting transfer prices by the relevant tax authorities. Furthermore, the absence of directly comparable data in many ways leaves the door open to determine a transfer price using other methods, including those where there is a greater variance of potential arm's length prices.

While LNG will perhaps never become as freely traded as oil, it is clear that the industry will grow significantly in both size and liquidity in the coming years.

It is an industry which is evolving all the time both in transfer pricing terms and a wider sense – indeed, the general transfer pricing principles outlined in this paper could well be obsolete in a few years. Tax authorities too, although often seeing these types of transactions for the first time, are becoming increasingly aware of the unusual nature of this industry and devoting considerable resources to educating themselves and ensuring that transfer pricing is not used to drive tax base erosion.

The combination of high growth, significant transaction value, market illiquidity, lack of direct comparable data and tax authority focus means that transfer pricing in this fascinating industry is never going to be far from the spotlight.

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Australia: A changing tax landscape

Business Tax Working Group ("BTWG") – Funding a tax rate cut for a two speed economy

The BTWG released a discussion paper on 13 August 2012 considering the case for a reduction to the company tax rate, including potential measures for funding such a reduction. The funding options raised for consideration can be described in three broad categories: financing, capital allowances and research and development ("R&D").

Firstly, the BTWG proposes the following possible options for tightening the thin capitalization rules:

- removal of the arm's length debt test;
- reduction of the safe harbor maximum debt limit from 75% to 60%;
- a reduction of the worldwide gearing ratio from 120% to 100%; or
- removing the thin capitalization rules entirely, and replacing them with an EBITDA-driven cap on the deductibility of interest.

Secondly, possible reforms relating to the capital allowances treatment of depreciating assets and capital expenditure include:

- reduction in the diminishing value rate for depreciation from 200% to 150%;
- removal of the capped effective life provided to depreciating assets used in oil and gas extraction;
- removal or reduction of the "first use" exploration deduction;
- removal of immediate deduction for exploration expenditure by large companies;
- exclusion of feasibility studies from exploration expenditure; or
- changes to depreciation on buildings.

The options raised would have significant implications for capital-intensive industries such as oil and gas.

Thirdly, the BTWG has identified options to better target the R&D tax incentive by removing or limiting the availability based on a company turnover threshold:

- removing the 40% non-refundable tax offset for companies with a turnover of greater than A$20 million per annum;
- imposing a turnover threshold above which the 40% non-refundable tax offset could not be claimed (such as A$10-$20 billion);
- imposing a cap on the amount that can be claimed annually under the 40% non-refundable tax offset (no cap amount is mentioned); or
- cutting the rate of the non-refundable tax offset to 37.5%.

The BTWG will review submissions on the various options and make its final recommendations to the Government in December 2012.

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The Esso decision

The High Court's refusal to grant special leave for Esso Australia Resources has confirmed that a payment made under a service agreement to a subsidiary to make available to the taxpayer trained personnel, equipment, and facilities to enable the conduct of petroleum exploration, production and marketing operations in Australia, and on the Continental Shelf, is not deductible for Petroleum Resource Rent Tax ("PRRT") purposes. As a result, the Australian Taxation Office ("ATO") has withdrawn a number of draft Taxation Rulings that related to these matters.

This decision has also brought into question the ability to apportion PRRT expenditure, which is inconsistent with the previous view of the ATO and generally accepted by industry. The ATO have indicated that while they will not seek to disturb historical assessments at this stage, they will be applying the approach handed down in the decision going forward. This results in significant uncertainty for the industry with regard to the deductibility of expenditure, and effectively renders the PRRT regime unworkable. Federal Government amendments to the PRRT legislation will be required to limit any unintended consequences arising from the Esso decision.

Changes to Australia's Transfer Pricing ("TP") regime

New TP legislation was passed by the Australian Parliament on 20 August 2012 and is now awaiting Royal Assent. The primary purpose of the new provisions is to ensure that the TP articles in Australia's tax treaties (the Associated Enterprises and Business Profits Articles) can be applied as an assessment power independent of the domestic legislation.

Broadly, the new provisions authorize the ATO to tax a "transfer pricing benefit," which is essentially the amount of profit which would, but for non-arm's length conditions, be allocated to an Australian entity or permanent establishment under a transfer pricing article in an applicable tax treaty.

Significantly, the provisions have effect for years of income commencing on or after 1 July 2004, with the retrospective application of the new legislation being its most controversial feature.

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However, the Government views the legislation as a revenue protection measure, pointing to the need to address uncertainties as to the operation of the existing transfer pricing laws, particularly following last year's Federal Court decision in the SNF Australia case.

This could have a major impact for taxpayers with ongoing ATO TP audits. The ATO has indicated that it has 40 such cases involving TP adjustments worth | A$1.9 billion in tax. For those taxpayers, the ATO now has legislative backing for what were previously only arguable views.

Living Away From Home ("LAFH") allowance changes

The Australian Government has passed changes to the legislation governing the taxation of LAFH benefits provided to employees. These changes come into effect from 1 October 2012 and are likely to have significant financial implications for all employers providing these benefits. The changes will apply to all existing and new arrangements, although there are some transitional provisions that will predominantly apply only to resident Australian employees.

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On 28 August 2012, the Minister for Climate Change and Energy Efficiency announced that Australia and Europe will be linking their emissions trading systems.

New rules

- All LAFH benefits will continue to be taxed under the Fringe Benefits Tax ("FBT") legislation.
- The LAFH exemptions and concessions for accommodation and food benefits will be limited to a maximum period of 12 months, irrespective of how long the assignment period is.
- Employees must demonstrate that they have a usual place of residence in Australia that they are living away from during the assignment period and that residence must be available for their use at all times during the period they are receiving the LAFH exemptions and concessions (which means the residence must be left vacant or with the employee's spouse and children still living in it).
- Employees will be required to substantiate their accommodation expenses.
- Food allowances will continue to be taxed on the same basis subject to the reasonable allowance amounts published by the ATO.

Foreign or non-residents (including those working on a 457 Visa) who are living away from a usual place of residence that is not located in Australia will not be entitled to the LAFH exemptions and concessions.

Transitional rules

There are some transitional rules that may apply to LAFH arrangements that were in place prior to 7:30 p.m. on 8 May 2012, provided they have not subsequently been renewed or varied in a material way.

- For resident Australian employees, the old LAFH rules will continue to apply to these arrangements up to the end of their assignment or 30 June 2014, whichever is earlier.
- For foreign or non-residents (including those working on a 457 Visa), the old LAFH rules will continue to apply to these arrangements up to the end of their assignment or 30 June 2014, whichever is earlier, only if the following conditions are satisfied:
  - The employee can demonstrate that they are living away from a usual place of residence that is located in Australia; and
  - The residence must be available for their use at all times during the period they are receiving the LAFH exemptions and concessions (which means the residence must be left vacant or with the employee's spouse and children still living in it).

Fly-in-fly-out and drive-in-drive-out arrangements

The new LAFH rules will not apply to these arrangements even where they include foreign or non-residents. There is also no requirement for the work location to be in a remote area for the accommodation and meal benefits to be exempt from FBT. However, it should be noted that the exemption for airfares for these arrangements continues to only apply where the work location is in a remote area.

Carbon regime – links to Europe

On 28 August 2012, the Minister for Climate Change and Energy Efficiency announced that Australia and Europe will be linking their emissions trading systems.

This arrangement is to commence no later than 1 July 2018 and will allow businesses to use carbon units from the Australian emissions trading scheme or the European Union Emissions Trading System ("EU ETS") for compliance under either system.

To facilitate linking, the Government will make two changes to the design of the Australian carbon price:

- the price floor will not be implemented (was initially intended to apply from 1 July 2015); and
- a new sub-limit will apply so that only 12.5% of liabilities will be able to be met by Kyoto units.

China: VAT reform pilot program launched in Shanghai expanded

China's State Council announced on 25 July 2012 that the Value Added Tax ("VAT") reform pilot program which commenced on 1 January 2012 in Shanghai will be expanded to eight provinces/cities, with the intention that the reform program eventually would be expanded to the entire Chinese mainland.

Under China's current indirect tax system, VAT is levied on the supply of goods, the provision of repair, processing and replacement services, and on imports at the standard rate of 13% or 17%, while Business Tax ("BT") is levied on the provision of other services and the transfer of intangibles and real property generally at a rate of 3% or 5%. The co-existence of the VAT and BT have led to a number of issues such as double or multiple taxation as no input tax credit mechanism is available under the BT system. The VAT reform pilot aims to resolve the double or multiple taxation issues that arise under the current indirect tax system, and will initially apply to the transportation and certain modern service industries. According to the pilot program, the taxation of specific sectors will transition to be subject to VAT rather than BT, and two new tax rates of 11% and 6% have been introduced, which will apply in conjunction with the current rates of 17% and 13%. The VAT pilot program also sets out new VAT provisions for oil and gas field services.

According to the previous VAT rule applied to oil and gas field services, Caishui [2009] No.8, qualified oil and gas field companies which provide productive services are subject to VAT at a rate of 17%. Productive services include geological exploration, well drilling, well logging, logging, well testing, well cementing, oil and gas testing, underground operation, oil and gas gathering and transporting, oil and gas extraction, offshore oil field construction, supply of water, electricity, heat and communication, oil and gas field construction, environmental protection, and other productive services *(e.g.,* transportation, design, information gathering, equipment leasing, etc., collectively referred to as "Other Productive Services").

The pilot program stipulates that oil and gas field companies which provide "taxable activities" should follow the new rules outlined below and that Caishui [2009] No.8 would no longer be applicable.

The co-existence of the VAT and BT have led to a number of issues such as double or multiple taxation as no input tax credit mechanism is available under the BT system.

An explanation of the pilot program published on the tax bureau's website further elaborates that for qualified oil and gas field enterprises, the term "taxable activities" specifically covers geological exploration, oil and gas gathering and transporting, and some of the Other Productive Services. In this respect, the tax treatment of these activities would be the following:

- geological exploration would fall within the modern service industry and a 6% VAT rate would be applicable;
- oil and gas gathering and transporting would fall within the transportation industry and an 11% VAT rate would be applicable;
- VAT treatment of all the other services mentioned in Caishui [2009] No.8 such as well drilling, well logging, well testing, etc., would remain unchanged.

Further clarification of the above VAT treatment of the various types of oil and gas activities is expected to follow within the next few months.

Cyprus: Industry & tax update

The development of the oil and gas sector in Cyprus continues. At present, only one license and Production Sharing Contract ("PSC") exists for "Block 12," issued to Noble Energy in October 2008. Noble is planning a second confirmatory appraisal well in the first quarter of 2013 following its announcement in January 2012 of a natural gas field discovery with an estimated resource range of 5 to 8 Tcf.

The Cypriot Government closed a second bid round on 11 May 2012 for licenses for an additional 12 offshore blocks. There were 33 applications received for 9 of the 12 blocks from 15 companies or consortia (representing 29 companies in total). It is expected that the Government will announce the successful bidders by the end of 2012 following the completion of the technical evaluation process in September and the subsequent approval of the Council of Ministers. Signature bonuses of up to EUR300 million are expected on issuance of the licenses and conclusion of PSCs.

In the meantime, the Government is continuing its discussions and negotiations with Noble Energy concerning the infrastructure required for landing the gas in Cyprus and liquefaction for export. The Government is also in negotiations with Israel concerning common infrastructure and export facilities for Israeli gas production from its offshore fields.

Confusion arose in the second bid round when the model PSC was released without a tax clause following continued statements by the Ministry of Commerce that "no tax is payable" on oil and gas production profits. The first bid round model PSC had included a tax clause providing that "applicable corporate tax shall be deemed to be included in the Republic [of Cyprus]'s share of Profit Oil" and "the portion of Available Oil which the Contractor is entitled to...shall be net of corporate tax."

> The Cypriot Government closed a second bid round on 11 May 2012 for licenses for an additional 12 offshore blocks.

> There is no specific regime within Cypriot income tax law concerning the oil and gas sector.

After several requests, the Ministry posted a clarification that each second round PSC would include a similar clause, although much to the disappointment of potential bidders modeling availability of foreign tax credits, the Ministry added that "a statement showing the amount of corporate tax paid for each specific calendar or tax year cannot be prepared or obtained."

Notwithstanding the above, there will still be a need for contractors to calculate their taxable profits and submit corporate income tax returns. There is no specific regime within Cypriot income tax law concerning the oil and gas sector. Taxable profits from trading operations are taxable at the normal corporate income tax rate of 10% and taxable profits are determined under a framework of deductions for expenses wholly incurred in the derivation of income and capital allowances for assets used in the trade. It is expected however that the tax authorities will issue some guidance in due course.

VAT law in Cyprus operates under the framework of the EU VAT Directive. The principal rate is 17%, likely to increase to 18% from 2013. Currently it is not clear whether Cyprus' Exclusive Economic Zone ("EEZ") is within the territory of Cyprus for VAT purposes and a statement is expected from the VAT authorities in this regard following their consultation with the Office of the Attorney General of Cyprus. In relation to customs duties, Cyprus applies the Community Customs Code, meaning that no customs duties apply to goods traded in Cyprus' EEZ beyond its territorial waters.

Falkland Islands: Update on tax developments

Background

Sitting some 460 km from the east coast of mainland South America in the South Atlantic, the small archipelago of the Falkland Islands has a population of little more than 3,000, and until recently fishing, sheep farming and tourism formed the mainstay of its economy. But the discovery of the Islands' first commercial oil reserves in 2010 at the Sea Lion complex in the North Falkland basin by UK based Rockhopper Exploration marked the start of an exciting new era in the Islands' history. With the recent announcement in July 2012 of farm-in arrangements with Premier Oil to jointly develop the Sea Lion field with a view to commercial production around 2017, the prospect of the Falkland Islands entering the international oil and gas arena could soon become reality.

More recently, August 2012 saw Texas-based Noble Energy become the first U.S. firm to sign an exploration deal in the territory, joining more established players such as Desire Petroleum, Falkland Oil and Gas Limited and Borders and Southern Petroleum in pursing exploration opportunities. This upsurge in activity has brought the fiscal regime of the Falklands (which, although a British Overseas Territory, has responsibility for its own tax system) increasingly into focus. As the oil and gas industry develops, both existing players and potential investors will be taking a keen interest in the evolution of an industry tax policy, which to date has been subject to little practical application.

History of the tax regime

The first significant exploration in the Falklands was seen in the 1990s, and in response to this the Falkland Islands Government introduced specific tax legislation for oil and gas activities. The legislation was based largely on prevailing UK legislation that existed at the time for oil and gas related activities on the UK Continental Shelf, and many similarities can still be seen between the two, including the principle of "ring fencing."

Although initial wells drilled during the 1998 drilling round recorded oil shows, none encountered commercially viable reserves, and for the next decade exploration activity in the Falklands was minimal. Thus, while tax legislation for the UK continued to evolve with the developments of the UK oil industry in this period, the equivalent Falklands legislation remained largely unchanged and untested.

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Increased commodity prices during the late 2000's saw an uptick in exploration globally with previously uncommercial fields regaining potential. This was seen in the Falklands with exploration activities being undertaken by a number of companies, culminating in Rockhopper's discovery of the Sea Lion complex in 2010. However, despite this recent activity the oil and gas tax legislation in the Falklands has, in general, remained largely unchanged from its original form.

Dispute with Argentina

As a backdrop to this, one cannot forget what the Falklands are undoubtedly most famous for – the disputed territorial claims between the UK and Argentina. The Islands have been a British Overseas Territory since 1833, but Argentina has long claimed sovereignty over the "Islas Malvinas" for which Argentina represents the nearest mainland territory. This dispute culminated most notably in Argentina's invasion of the Islands in 1982 and the two month long Falklands War that ensued. Although this ultimately ended in defeat for Argentina, it continues to pursue its claims, and the recent discovery of commercial oil reserves has brought this dispute back into the international spotlight.

Future developments

With the prospect of commercial production now looking increasingly possible, it will be in the interests of both investors and the Falklands Government to ensure a robust and modern tax regime is developed to ensure the potential benefits of the Islands' petroleum resources can be realized. Indeed, the first signs of policy development have begun to appear. Spurred by the flurry of license buy-ins, an Extra Statutory Concession was issued earlier this year to facilitate the deferral of corporation tax on chargeable gains arising on certain farm-out arrangements. It is also understood that the Falklands Government is in the process of commissioning a review of the existing legislation, which will no doubt involve some form of consultation with license holders.

Although the Falklands oil and gas tax regime has so far had a degree of similarity with that in the UK, given recent criticisms of the competiveness of the UK's regime it will be interesting to see whether the Falklands Government chooses to emulate the UK approach, or takes its policy in a different direction. Either way, if the oil potential of the Falklands is to be fully realized, then establishment of a regime that encourages continued investment in the region with an emphasis on stability and security will no doubt be a priority for all.

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United Kingdom: Decommissioning tax relief consultation and new field allowances

Two significant changes to the North Sea fiscal regime have been welcomed by the industry: decommissioning tax relief certainty consultation and new field allowances.

Decommissioning tax relief certainty consultation

Following discussions with industry, in the Budget 2012, the Government announced that legislation would be enacted in 2013 giving them the power to enter into decommissioning relief deeds ("DRDs"), with companies subject to UK oil and gas taxation to provide certainty on the tax relief for future decommissioning costs. In July 2012, the Government released a consultation document outlining its proposals in respect of DRDs and joint government and industry working groups have been set up to work through the issues. The consultation closed on 1 October 2012 and draft legislation is envisaged in late 2012, although working groups are expected to continue through to Budget 2013.

The aim of these changes is to provide certainty regarding tax relief for decommissioning, such that security in respect of decommissioning obligations (for which there is joint and several liability between field partners) can be provided on a net (post-tax) rather than gross (pre-tax) basis as is currently the case.

The industry body, Oil and Gas UK, believes that up to £40 billion of additional investment could be unlocked through the changes if they provide the required certainty for investors, through a release of funds for investment, removing barriers to M&A and extending field lives.

Under the proposals, the DRD will be available to all companies that are or have been subject to North Sea taxation (ring fence corporation tax, supplementary charge and petroleum revenue tax ("PRT")). If the specified level of relief under the DRD is not achieved through the tax code, a shortfall payment may be claimed from the Government. The mechanism for this will be the "reference amount." This specifies the amount of tax relief that a company would be entitled to receive in various circumstances, based on the tax law that will be in place on Royal Assent in 2013 (preserving relief if a tax such as PRT was abolished).

Where a company is paying for its own decommissioning costs in a "non-default scenario," then the DRD guarantees relief at the rate of tax paid, based on its own tax capacity.

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Where a company pays for someone else's decommissioning costs in a "default scenario," relief would be guaranteed at 50% (for ring fence corporation tax and the supplementary charge), regardless of tax history. Where relevant in a default tax scenario, PRT relief will also be guaranteed based on either the tax history of the company incurring the expenditure, or the tax history of the defaulting party, whichever is greater. The intention is that this will provide participants sufficient assurance, such that securitization can be provided on a post-tax basis.

New field allowances

Shallow-water gas field allowance

As part of the UK Government's strategy to encourage investment on the UK Continental Shelf ("UKCS"), on 25 July 2012, a new £500 million field allowance for large shallow-water gas fields was announced. It will be available for fields:

- whose development is authorized for the first time on or after 25 July 2012;
- with a share of gas reserves greater than 95% based on the central estimates of oil and gas reserves at the time of development authorization; and
- with a water depth less than 30 meters.

Field allowances were originally introduced in 2009 to provide an incentive for investment in "marginal" fields. This new allowance protects the first £500 million of income fields from the 32% supplementary charge. The field allowances do not affect ring fence corporation tax (at 30%) which is still applicable on all taxable profits from the field.

UK Chancellor of the Exchequer George Osborne has been quoted as having said in a speech on 8 October 2012 that HM Treasury is consulting on a "generous new tax regime" for shale gas.

The maximum allowance will be available to fields with a central estimate of gas reserves between 10 billion cubic meters ("bcm") and 20 bcm, tapering to no allowances for fields at 25 bcm and above.

One of the fields expected to benefit from this allowance is Cygnus, whose development was also announced in August 2012.

Brown field allowance
Following recent consultation on the potential to bring new "brown field" development within the field allowance rules, the Government has now announced the introduction of a "Brown Field Allowance" which is intended to encourage incremental developments of certain older fields, as well as preserving existing infrastructure.

The allowance will shield profits from fields with qualifying projects from the 32% supplementary charge up to a maximum of £250 million (£500 million for projects in fields paying PRT). It will be available from the accounting period in which incremental production is expected to start. The field allowance for a qualifying project will be £50 per ton of expected incremental reserves for projects with a verified expected capital cost per ton of incremental reserves of £80 or greater, tapering to nil where these fall below £60.

Qualifying projects will be those increasing expected production from an offshore oil or gas field as described in a revised consent for development authorized on or after 7 September 2012, and with verified expected capital costs per ton of incremental reserves in excess of £60 million.

Projects involving enhanced oil recovery using carbon dioxide are initially outside the scope of the allowance, and a Government review of the effectiveness of the revised allowances will take place in 2015.

United Kingdom: Informal consultation on special UK tax regime for shale gas

UK Chancellor of the Exchequer George Osborne has been quoted as having said in a speech on 8 October 2012 that HM Treasury is consulting on a "generous new tax regime" for shale gas.

Under current law, exploration and extraction of shale gas would fall within the existing "ring fence tax regime" and would be taxed at an effective rate of 62%, assuming any shale discoveries were "new fields" and hence outside the scope of Petroleum Revenue Tax. According to Treasury officials on 9 October 2012, the current consultation is informal, with individual companies, and depending on the outcome, a further announcement may be made at the time of the Budget in March 2013.

United States: Tax transparency in the oil and gas sector

Introduction

The U.S. has instituted new disclosure requirements for the extractive industries which may create a business environment of unprecedented transparency for oil and gas companies.

The requirements detailed below will only affect companies with a U.S. listing. However, their impact will stretch well beyond America, with the EU expected to introduce similar rules next year.

Dodd-Frank

The Securities and Exchange Commission ("SEC") was required to adopt tax transparency rules under Section 1504 of the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd Frank").

Under the SEC's rules, resource extraction issuers including oil and gas groups with a U.S. listing will be required to disclose, through the submission of a new SEC Form SD, taxes, royalties, fees, production entitlements, dividends, and payments for infrastructure improvements made to governments for the purpose of their oil and gas operations. Form SD, which will be publicly available, will provide granular detail on payments made on a project-by-project basis, including the recipient of the payment and the business segment of the group making the payment.

Resource extraction issuers

The SEC's rules apply to "resource extraction issuers." In effect, this means all such companies that file reports, including for example, Forms 10-K, 20-F, or 40-F with the SEC and engage in the "commercial development of oil, natural gas, and minerals." Foreign companies with U.S. listings are not excluded from the disclosure requirements. Furthermore, foreign companies will be subject to the disclosure requirements if their parent companies have a U.S. listing. Disclosure is not limited to payments made by consolidated groups; payments made by an issuer's subsidiaries or by other entities such as equity method investments and joint ventures will also need to be disclosed if the issuer controls such other entities.

Commercial development of oil, natural gas and minerals

The final rule clarifies the meaning of "commercial development of oil, natural gas and minerals" and expands on the fact that the rules apply to "exploration, extraction, processing, export and other significant actions relating to oil, natural gas or minerals, or the acquisition of a license for any such activity, as determined by the Commission."

The SEC has stated that the rules will not apply to activities that are "ancillary or preparatory" in nature, such as the manufacture of equipment used for extraction. Nor will they apply to the transportation (when not directly related to export), storage, or marketing of oil and gas. Significant uncertainty remains for many taxpayers in the industry, most notably oil field services companies, over whether the rules will apply to them.

Project-by-project reporting

Companies that are subject to the rules will need to disclose payments on a "project-by-project" basis. The SEC has not defined the term "project," but has indicated that it will generally mean a specific contract between affected companies and governments for the commercial development of oil or gas (*e.g.,* a particular license).

Reporting on a project-by-project basis could prove challenging. Many relevant payments may not relate to a specific project. The SEC noted its belief that extractive issuers should not be required to allocate payments for obligations levied at the entity level. Most corporate income tax, for example, is levied on an entity rather than a project basis. Therefore, for tax payments that are made at an entity level rather than a project level, the issuer is permitted to disclose those tax payments without specifying the projects.

Reporting on a project-by-project basis could prove challenging.

Payments

Affected companies will also need to understand what types of payments they are required to disclose. The SEC has stated that the payments to governments which must be disclosed include taxes, royalties, fees, production entitlements, bonuses, dividends, and payments for infrastructure improvements. These payments include payments in-kind (*e.g.,* a payment in the form of oil or gas). "Taxes" include those on corporate profits, corporate income and production, but not personal income taxes or those levied on consumption such as VAT or sales taxes. Companies have to disclose payments that are US$100,000 or more, whether a single payment or a series of related payments during the most recent fiscal year.

Governments

The final rule requires resource extraction issuers to disclose certain payments made to both the federal government and foreign governments. The term "federal government" refers only to the United States Federal Government and excludes U.S. state and local governments. Conversely, the term "foreign government" includes foreign national governments along with any foreign sub-national governments, such as a state, province, district or territory. Payments to companies that are majority owned by a government are also subject to the disclosure requirements.

Form of disclosure

The required disclosures must be made for periods ending after 30 September 2013 in a separate report (Form SD) filed with the SEC within 150 days of the extractive issuer's fiscal year end. The final rule also clarifies the transition provisions for its implementation. Resource extraction issuers whose fiscal year begins prior to 30 September 2013 are required to disclose payments made from 1 October 2013 through the date of their fiscal year end. In addition, there is no audit requirement for the disclosures but it is anticipated that some resource extraction issuers will seek external assurance over amounts reported.

Wider implications

While Section 1504 only imposes requirements on U.S.-listed companies, other countries are expected to introduce similar rules.

On 18 September 2012, for example, the Legal Affairs Committee of the EU Parliament voted in favor of project-by-project reporting with a minimum threshold of €80,000. The next stage will be the joint decision process between the Council of Ministers and the European Parliament.

Conclusion

Despite the complexity, controversy and delay, the new U.S. transparency rules are here. Affected oil and gas companies will need to (1) understand their requirements; and (2) consider and respond to the strategic and operational challenges that they pose. In particular, they should consider whether their current systems are able to provide the required information and what changes could be necessary. Oil and gas companies will also need to consider how the disclosures are to be made given that there is currently no additional guidance, as well as consider the risks and opportunities that such disclosure may present.

What is clear is that the new transparency requirements will have a far-reaching impact on several of the business functions within oil and gas groups, including finance, tax, legal, internal audit, procurement, government and social affairs, and operations. These functions will need to work together to effectively facilitate compliance with the rules and manage possible implications of the disclosures.

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Talk to us

For additional information regarding global oil and gas resources, please visit **www.deloitte.com/oilandgas.**

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Designed and produced by The Creative Studio at Deloitte, London. 22321A