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Renewable energy is often synonymous in people’s minds with credits and incentives. However, there are two other critical tax issues facing renewable energy companies that can make or break an investment. *Shannon Blankenship, Allison Easley* and *Christine Piar* of Deloitte discuss how these tax issues can impact companies in this industry, some common situations, and identify areas for consideration and planning.
Welcome to International Tax Review’s third energy industry guide, published in association with Deloitte, analysing the tax and transfer pricing implications for taxpayers operating across the oil and gas sector.

The guide offers an insight into the sector and provides readers with a non-technical background with the latest information on how energy companies are taking advantage of non-traditional energy sources as well as updating techniques used for decades.

Given the complexity and variety of tax issues across the sector, it is no surprise that taxpayers can often be left confused trying to keep up-to-date with all the changes. Just as they feel they are on top of things, governments amend and update tax law to add another layer of complexity.

One country where energy is playing a key role in tax reform is the US.

In a June Senate Finance Committee hearing into US tax reform, the impact of reform on energy policy was assessed, with committee chairman Max Baucus saying it provides the energy sector with an opportunity to make real progress in securing future energy supply while also simplifying the tax code.

“[Tax reform] can move us further from foreign oil. It can lead us down a road to diverse, clean and secure energy resources,” said Baucus. “So let us seize this opportunity. Let us use tax reform to ensure our country has a more secure and diverse energy supply.”

Baucus is right. Governments around the world are aware that traditional energy source are finite and so tax will be a key player in how countries establish new sources, attract investment and develops new technology.

The US is not the only country using tax to enhance the sector. In March, the UK government announced plans to introduce legislation – expected in 2013 – to restrict the rate of decommissioning tax relief to 20% for supplementary charge purposes.

Of greater importance was the further announcement, outlined in the overview of tax legislation and rates, that the government will introduce legislation in 2013 giving it statutory authority to sign contracts with companies operating in the UK and UK Continental Shelf, to provide assurance on the relief they will receive when decommissioning assets.

While these are just two examples of change, many more are highlighted in this guide. We hope these articles will help you when dealing with your tax affairs in the global energy sector.

Jack Grocott
Editor
International Tax Review
Introduction

Fuelling controversy: tax and transfer pricing issues in oil and gas

Randy Price and John Wells, National Transfer Pricing Leaders – Deloitte Oil and Gas Industry

On behalf of our Deloitte Tax colleagues that focus on tax and transfer pricing issues within the oil and gas (O&G) industry, we are pleased to present this selected collection of thought papers on industry developments and issues.

While many readers may have some knowledge of issues within this industry, we know that one of the key challenges that the O&G industry faces is addressing the breadth of significant tax, transfer pricing, and investment issues that are specific to it. Therefore, we begin our guide with a primer on the O&G industry segments (such as upstream, mid-stream, and downstream), transfer pricing fundamentals, and transfer pricing issues specific to the O&G industry in an attempt to broaden the general knowledge base of international tax professionals or others interested in this dynamic industry. Next, we turn our attention to various transfer pricing issues and challenges related to the industry. We focus one paper on the rapidly expanding global shale/tight oil and shale gas play and highlight some of the transfer pricing issues inherent in these cross-border investments of oil companies. We then address transfer pricing considerations of intra-group financing to bring attention to the challenges of pricing cross-border loans in this capital intensive industry. We have also included an overview of recent tax developments for selected countries that have a significant or expanding presence in today’s O&G Industry. And finally, we highlight certain transfer pricing and tax considerations in the rapidly expanding renewable energy sector where project viability often turns on various credit incentives.

Given the complexity and variety of tax issues within this industry, this guide should be the starting point rather than the finish line for all of your O&G industry related transfer pricing and tax inquiries. For more information regarding transfer pricing issues in specific countries, and about Deloitte’s tax practice in those jurisdictions, please refer to the list of Deloitte member firm contacts contained in Deloitte’s Global Transfer Pricing Desktop Reference, which can be found at www.deloitte.com/tax/strategymatrix.

We hope you find our publication interesting and, more importantly, of practical use, and we invite you to contact our leading team of professionals or your local Deloitte contact if you have any questions.

Yours truly,

Randell (Randy) Price and John Wells
National Transfer Pricing Leaders – Deloitte Oil and Gas Industry

Nadim Rahman contributed to this publication as Deloitte’s editor of all the articles.
To the uninitiated, the enterprise by which companies explore for hydrocarbons, bring them to the surface, and deliver them to our cities seems remarkably simple. While the world is busy consuming about four million barrels of oil every hour – an amount equivalent to the daily production of one “Super Major” exploration and production (E&P) company and the carrying capacity of two oil tankers – most of us are blissfully unaware of the complex systems, processes and tools necessary to fuel our economy. Indeed, the incredible risks associated with these activities were, until recently, not widely understood by those outside the industry.

Events taking place in the U.S. Gulf of Mexico during the spring and summer of 2010 arguably destroyed some of this naïveté forever. On April 20, 2010, the Deepwater Horizon, a huge dynamically positioned drilling rig located 49 miles off the Louisiana coast and drilling in 5,000 feet of water to tap hydrocarbon reservoirs 13,000 feet below the sea floor, exploded, resulting in the loss of 11 lives. Efforts to contain the well through engaging the blowout preventer (BOP) using remotely operated underwater vehicles, stuffing the damaged BOP with heavy drilling fluids, and capping the well head with a containment dome, all failed. The deep reservoir, which was pressurised at more than a thousand pounds per square inch, was effectively “killed” months later by the drilling of two relief wells, re-cementing, and the replacement of the 300 tonne BOP.

These painful containment events were captured for the public on television and made visible the dynamic and uncertain world of oil E&P. Commentary around the spill compared E&P activities to exploring outer space, and made the point that the technology and processes necessary to carry this out safely are still being developed. Due to a moratorium on offshore drilling to address these concerns, activities at 33 well sites in the Gulf were suspended.

While offshore activities suffered from the conflagration in the Gulf, US land-based E&P operations were experiencing a blowout of a different and more positive kind. “Unconventional” sources of hydrocarbons – tight gas, coal bed methane, and perhaps most importantly, gas in shale formations – have completely transformed the global energy landscape. These resources, which could not be exploited previously, are now a commercial reality thanks to improvements in drilling and completion techniques such as hydraulic fracturing, horizontal/directional drilling, and real-time visualisation of the drill path.

Due in part to these innovations, the US shale gas industry grew by 45% a year between 2005 and 2010. Indeed, of the 584,670 net new private sector jobs created in the US between 2003 and March 2012, 209,630 have been in the O&G production sector, indicating that 36% of all net new private sector jobs created in the US during the last 10 years have been in the O&G production sector, resulting in 86% increase in employment in this industry. The abundance of natural gas has also invigorated manufacturing industries that depend upon gas as a feedstock (such as petrochemicals). Just a few
years ago, the US was expected to be a big importer of liquefied natural gas (LNG) and built an infrastructure to regasify more than 100 billion cubic meters of imported natural gas per years. The US is now estimated to have enough natural gas to supply its domestic needs for over a century and these regasification facilities remain mostly idle. While European and Asian consumers currently pay four to six times more for natural gas than their counterparts in the US and would do well to exploit their own unconventional reservoirs, the confluence of favorable regulations and infrastructure that has made this price differential possible is not as robust in other countries.

As the narrative above emphasises, the O&G sector is a mixture of both unfortunate and happy coincidences, the complexities of which even industry participants struggle to forecast correctly. Additionally, whether on land or sea, the act of finding and producing hydrocarbons is expensive, complex, and generally not well understood. But for all the complications associated with the business end of this industry, the tax issues in the energy sector are even more difficult to navigate. Due to the fact that most multinational O&G companies are forced to stretch their supply chains across far flung places and exchange billions of dollars of commodities, equipment, engineering services and intangible/intellectual property (IP) among their controlled affiliates, transfer pricing risks are one of the largest tax uncertainties faced by these companies.

The O&G supply chain: an overview of the industry and functions of key participants

The accumulation of commercial quantities of O&G in the Earth’s surface is actually a rather rare occurrence. Hydrocarbons form deep beneath the Earth’s surface when organic materials deposited in ancient sediments slowly transform in response to intense heat and pressure. Over the course of millions of years, these materials “cook” into liquid (crude oil) and gaseous (natural gas) hydrocarbons. The hydrocarbons escape their source rock through porous mineral layers such as faults and fractures and tend to migrate upward because they are lighter in density than other fluids in the rock pores. If there is a path that leads to the surface, the hydrocarbons will emerge above ground in a seep or tar pit. If an impermeable layer of rock blocks the migration, a trap is formed and the hydrocarbons can accumulate in porous rock beneath the trap. Traps are often formed by salt domes, shale, chalk and other formations. The business of drilling for O&G consists of finding and drilling into these reservoirs of porous hydrocarbon-filled rock.

Exploration and production

The E&P companies operating in this sector focus on the acquisition, exploration and development of properties for the production of crude oil and natural gas from underground reservoirs. This process generally takes several years to complete. A geologist starts the process of finding hydrocarbons by looking for large structural traps, source and reservoir rocks in a particular geological basin. Seismological techniques are used to investigate subsurface conditions and construct subsurface maps and surveys of the reservoir. Seismic exploration involves four steps: acquisition of data about the geology by recording sound waves as they echo off various boundaries of rock layers; processing the seismic surveys using high powered computers and software algorithms that apply mathematical and geophysical theories about seismic reflections; displaying the processed data in 3D and 4D (with the 4th dimension being time) formats in visualisation rooms; and interpretation of the seismic mapping by geophysicists and geologists.

Some of the greatest improvements in petroleum exploration during the last two decades have involved new seismic acquisition techniques and computer processing of digital seismic data. Since seismic surveys contain huge amounts of data, various advancements are purely the result of increases in computing power. But considerable progress has also been made from the development of advanced algorithms that improve seismic imaging, especially in subsalt formations. Many offshore basins have extensive layers of salt through which traditional seismic methods are ineffective. These new algorithms have allowed E&P companies to identify salt domes and the reservoirs trapped beneath them. Several recent discoveries in the Gulf of Mexico and off the coast of Brazil point to the success of these techniques. The Brazilian find, 150 miles off the coast of Rio de Janeiro, could contain eight billion barrels of oil, buried under four and a half miles of water, sand, rock and salt deposits.

The information gathered through seismic surveys determines where exploratory wells are drilled. Seismic records, however, do not identify the individual sedimentary rock layers and must be supplemented with additional testing. To avoid damaging the reservoir, this normally involves tripping the drill pipe out of the hole and using wireline well logs and drillstem tests, whereby an instrument is lowered down the well to record the properties of the formation, well pressure, the fluids in the well, the geometry of the wellbore, etc.

Modern rotary drilling rigs have a number of complicated parts, each designed for a single purpose, but operating in a mechanical symphony: a derrick that provides the frame to raise and lower equipment into the hole; a hoisting system; a mud-mixing and circulating system including pumps and tanks (drilling mud is used to remove cuttings from the well, to balance pressure in the reservoir and keep the hole from collapsing); a top drive engine to rotate the drill string; the
BOP, which prevents pressurised gas and liquids from escaping the well and has hydraulic rams to shut the drill pipe or disengage the rig if control of the well is lost; equipment racks; housing to shelter meters, equipment, and offices/quarters for rig personnel.

While most people think of underground O&G deposits as deep pools of hydrocarbons, O&G reservoirs are typically wider than they are deep. It is therefore difficult to access the whole reservoir by drilling vertically. Starting in the 1990s, the industry began to develop technologies and processes to keep the wellbore in the pay zone of the reservoir. Chief among these were rotary-steerable drilling assemblies that allowed for horizontal or directional drilling.

Directional drilling allows reservoirs to be tapped a long distance from the well site. It includes all forms of drilling where the end point of the well is distant from the well site rather than directly beneath it. Directional drilling techniques have been enhanced by the placement of logging and measurement devices just above the drill bit on measurement-while-drilling and logging-while-drilling tools and systems. These allow the operator to visualise the drill path through the Earth in real time, to make corrections to stay in the pay zone, and avoid obstacles. Horizontal drilling may be three or four times more costly, but the production factors can be as much as 15 to 20 times better than conventional vertical wells.

After the well is drilled and tested, there are two options for the E&P company: the well is either plugged and abandoned as a dry hole or, if commercial amounts of oil and/or gas are found in a test well, the process moves to the completion stage by setting pipe. Completing the well is typically more expensive than drilling a well. During this stage, production casing is screwed together, lowered into the well and cemented to the outside of the wellbore. After the cement job, a wellhead is installed. This is a combination of steel flanges, spools, valves, chokes and manifolds, assembled into what is known as a “Christmas tree,” which is designed to provide surface control of the subsurface fluids. Subsea production systems, or “wet trees”, are complicated hydraulic and electrical structures installed on the sea floor and connected to floating production, storage, and off-loading vessels (FPSOs), subsea pipelines, or other platforms at the surface.

One or more flow paths are then constructed by shooting holes in the casing and cement and into the reservoir along production zones using a perforating gun. This enables hydrocarbons to travel between the reservoir and the earth’s surface. Production tubing is run through the casing and pumps are installed (most oil wells require a pump to lift the liquids to the surface).

Even after the well is successfully completed and starts producing it may not be profitable. Some of the most common reasons are: mechanical failures; the wellbore missed the target zone or was improperly placed within the zone; permeability of the reservoir geology was low; the well failed to intersect fractures; drilling damaged the formation; drilling mud or chemicals leaked into the formation; the well traversed unexpected variations in rock formations causing water coning or sand to invade the wellbore; the presence of flow barriers, such as shale streaks inhibited production; or feasibility studies were poor.

A number of special-purpose logging and measurement tools may be lowered into the cased-hole to evaluate the condition of the well and reservoir. Well interventions can range from a workover to clean-out and repair the well, re-cementing, multi-zonal production, well stimulation, or abandoning the well. Since production rates in all wells decline as the reservoir is depleted by production, well stimulation is a common solution to increase production. An important process in this regard, especially in unconventional reservoirs, is hydraulic fracturing. This process, which was developed in 1948 to replace the (dangerous) use of explosives to stimulate wells, involves pumping large volumes of water, chemicals and sand under high pressure into the reservoir to split the rock and increase permeability. This process, combined with horizontal drilling and other technologies, increases O&G production rates up to 30 times initial rates and has made possible the US shale gas plays discussed above. Enhanced oil recovery techniques, such flooding the well with surfactants (such as detergents) or carbon dioxide, are an important development area for E&P companies as these methods are anticipated to increase production rates in mature wells and in formations with low permeability.

Ultra-deep water discoveries of what appear to be large deposits of O&G have been found recently off the coasts of Angola, Brazil, Sierra Leone, and Nigeria and in the Gulf of Mexico. Accessing these reservoirs will be extremely difficult as the spot where the drill bit hits the seafloor is some 5,000 feet or more below the rig floor and the target reservoir may be another three miles below the seafloor. Indeed, the cost of offshore drilling activities escalate almost exponentially with water depth. Given these costs and the concerns mentioned above about offshore drilling in general, it is not surprising that E&P and oilfield services companies have begun to invest heavily in the development of ultra-deep water drilling techniques, tools, and processes, including remotely operated underwater vehicles, well control/containment devices, rig automation, smart algorithms to address alarm management, training, maintenance procedures/documentation (especially for the BOP stack), and equipment that can withstand the high pressure and high temperatures required for drilling in this environment.

Equipment and oilfield services

What makes the O&G industry unique is not just the difficulty and risks faced by its participants, but also the fact that there are so many companies coming together at the well site to undertake this enterprise. Most of the drilling and completion activities discussed above are not performed by the E&P companies.
themselves, but by companies that operate in the equipment and oilfield services sector of the O&G industry. Some 85% to 95% of the money that E&P companies spend to develop O&G opportunities goes not to their own engineers, scientists and operating staff, but to service companies and suppliers.

Consider the list of oilfield market segments in Table 1. Hundreds of independent companies operate in each of these segments around the world. These companies manufacture equipment or build it on site, rent, repair and maintain it once in operation, and provide related products to E&P companies. Along with every piece of equipment and tool comes a plethora of services. The largest market segments in terms of global revenue are offshore contract drilling, offshore construction services, pressure pumping services, land contract drilling services, tubular goods (such as drilling pipe), geophysical equipment and services (such as seismic), rig equipment, subsea equipment, wireline logging, and directional drilling services. All in, these segments represented $189 billion worth of equipment and services in 2011. Revenue for the whole oilfield equipment and services market was $275 billion in 2011.

A typical E&P endeavour may have different companies performing each of the activities listed in Table 1. It is difficult to think of a more fragmented industry whereby so many critical processes and activities are outsourced. Moreover, these oilfield services companies also work together with independent oil companies (IOCs) and national oil companies (NOCs) to develop the intellectual property and innovations necessary to respond to evolving demands and are often relied upon to fill engineering gaps faced by the E&P companies. Recently, the whole industry has been focusing on technologies and processes that better integrate the activities of these disparate groups of service providers and to develop knowledge sharing platforms so that information learned on one well can be leveraged.

Midstream sector
The gathering, processing, storage, and transmission of natural gas, and the gathering, storage, and transportation of crude oil are the main operations of the midstream sector. Crude oil and other products are transported internationally in barges or tankers on water, and on land by trucks, and pipelines. Natural gas typically moves via pipeline from the producer to the gatherer or transmission company, and then on to the distributor. These products are typically stored in bulk terminals, refinery tanks, pipeline tanks, underground salt domes, barges, tankers, and inland ship bunkers.

**Table 1: Oilfield market segments**

| Artificial lift                      | Offshore contract drilling |
| Casing & tubing services            | Oil country tubular goods |
| Casing & cementation products       | Petroleum aviation        |
| Coiled tubing                       | Pressure pumping services  |
| Contract compression services       | Production testing        |
| Completion equipment                | Rental & fishing          |
| Directional drilling                | Rig equipment             |
| Downhole drilling tools             | Solids control            |
| Drill bits                          | Specialty chemicals       |
| Drilling completion fluids          | Subsea equipment          |
| Floating production services        | Surface data logging      |
| Geophysical                         | Surface equipment         |
| Inspection & coating                | Supply vessels            |
| Land contract drilling              | Unit manufacturing        |
| Logging while drilling              | Well servicing            |
| Offshore construction               | Wireline logging          |


**Downstream sector**
The downstream sector consists of mainly refining and marketing activities for crude oil, refined products, and natural gas. This includes the refining of crude oil into various products like gasoline, jet fuel, and diesel. Once the oil products are refined, they are sold to wholesale distributors, who sell to retailers and industrial users. Gasoline may also be sold directly by refiners to retail gasoline stations bearing the company’s brand name and emblem or independent dealers who own their stations and sell branded gasoline and other products from one or more oil companies. The distributors of natural gas and gas utilities receive their supply from transmission pipelines and deliver it to the public through their own distribution facilities. Their customers include residential, industrial, commercial, and electric utility end-users.

The different segments of the O&G industry are depicted in Diagram 1.

**Transfer pricing regulations and guidelines**
The US Treasury Regulations section 1.482 (Treas. Reg. § 1.482) generally require that transactions between related parties occur at prices consistent with those between unrelated parties. This is based on the arm’s-length principle, which is also adopted in article 9 of the OECD Model Tax Convention. Specifically, Treas. Reg. § 1.482 states that: “A controlled trans-
action meets the arm’s-length standard if the results of the transaction are consistent with the results that would have been realised if uncontrolled taxpayers had engaged in the same transaction under the same circumstances (arm’s length result).”

The generally agreed upon practices of the member countries of the OECD for determining transfer prices are addressed in the OECD report Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations (OECD Guidelines). The OECD Guidelines and Treas. Reg. § 1.482 set out methods for establishing arm’s length transfer prices for tangible goods, services, technical assistance, trademarks, or other assets that are transferred or licensed between related or controlled parties. These guidelines are widely accepted globally, with most countries formulating their transfer pricing rules around the guidelines, while others enact specific stringent regulations which are not far off from the purview of the guidelines. In the US, the Treas. Reg. § 1.482 describe a set of methods that practitioners may use to determine whether the prices charged in controlled transactions are consistent with an arm’s-length standard. Practitioners may also apply methods that are not specified in the regulations if they are likely to yield a more accurate result than the specified methods. In practice, there is little difference between the transfer pricing methods described in the OECD Guidelines and those in Treas. Reg. § 1.482, other than the fact that latter have specified methods for cost sharing arrangements that address the joint development of intangibles between two or more related parties.

In addition to specific tax regulations addressing the energy sector, many petroleum exporting countries are adopting transfer pricing documentation requirements. These countries include Brazil, Canada, Kazakhstan, Mexico, Nigeria, Norway, Russia, and Venezuela, among others. Interestingly, Russia’s recent regulatory changes have been driven by the government’s quest for ways to avoid loss of tax revenues and the accompanying capital flight allegedly generated by activity in the O&G industry. In general, there has been a consistent rise in the number of countries with transfer pricing requirements, especially in emerging markets such as China, Russia, Brazil, and India. The number of countries with transfer pricing rules stood at 54 as of 2012 compared with 12 in 1994.

**Diagram 1: Oil and gas supply chain**

**Transfer pricing issues in O&G industry**

Transaction flow and transfer pricing in the industry

For transfer pricing practitioners, the energy sector has all the excitement one would want, as multinational participants exchange high volumes of tangible products (oil, gas, chemicals, tools etc.), technical engineering services, loans, and technology on an intercompany basis. Transfer pricing issues cut across each of the streams in the O&G supply chain, especially for the vertically integrated “Super Major” E&P companies. More than 40% of the US cross-border transactions in the O&G sector are actually intercompany transactions between related parties, as explained below.

Of the total O&G products and equipment imported to the US during 2011 of $423 billion, about $175 billion, or 41%, were transactions between related parties. In 2002, only 24% of total O&G imports were related party transactions. In 2011, the amount of US O&G product and equipment exports was about $119 billion, 40% of which were related party transactions; this compares to 27% of the total exports in 2002. These figures suggest a growing importance of intercompany transactions in the O&G industry. The industry as a whole makes up 16% of total US imports and exports. Table 2 shows the 2011 total US transactions and related party transactions for the O&G industry.
The largest intercompany transaction in this industry involves the purchase and sale of crude oil, natural gas and various refined products from upstream producers to the midstream and downstream sector and end users. As can be seen in the table above, multinational energy companies exchanged more than $200 billion worth of hydrocarbons on an intercompany basis in the US during 2011. Typically, these transactions are based upon market price indices that are widely used in the industry, such as Platts, the Oil Price Information Service (OPIS), and the New York Mercantile Exchange (NYMEX). Transactions tied to these benchmarks, whether between related or third parties, are often referred to as being priced “at index” and normally include a “differential” term that adjusts for crude quality (such as heavy/light), location, and other differences relative to the referenced index.

Crude oil and gas are transported using the midstream operations of a third party or an affiliate of an E&P or downstream company. The crude oil sold to a related party refiner serves as the feedstock used to produce refined products. These products are sold to petrochemical manufacturers or retail marketers, which could be either a third party or an affiliate of the refiner. Apart from the sale of crude oil, natural gas and refined products, other tangible transactions include the sale or lease of drilling and production tools and equipment, rigs, offshore construction and production vessels. Consumables, such as sand, mud, water, chemicals and cement must also be used to drill and complete a well. As mentioned previously, a great number of oilfield services companies specialise in the manufacture and delivery of these various products to IOC’s and NOC’s.

Drilling and production problems require well interventions and workovers – solving mechanical and reservoir issues at the well. Each of these activities has a heavy engineering component and involves specialised tools, equipment, processes and software. Technical services are performed by IOCs, NOCs and oil field services companies, both on a third party and intercompany basis.

To understand the nature of intercompany services in the upstream segment of this industry, it is important to know that the commercial venture of exploring and producing hydrocarbons is typically carried out by multiple unrelated parties, each of whom has a financial interest in the property. The obligations of each party are governed by a number of contractual relationships, such as a joint operating agreement (JOA) and production sharing contract (PSC). A JOA generally governs the relationship between the working interest partners in a joint venture. The operator, typically the E&P company with the largest working interest in a property, has the benefit of being able to manage the project, providing technical resources, decision making and management services to the JOA.

The IOC’s host country activities generally involve the use of a controlled foreign corporation (CFC) that is part of a PSC with either an NOC in the respective country, local governments, or other international IOC’s that are party to a JOA. Depending upon the jurisdiction, the IOC may own a working interest and operate the project, or it may have working interest with another investor being the operator. In some instances, petroleum exporting countries may restrict the working interest percentages of foreign E&P companies, thus reserving rights to operate the project to local entities or NOC’s. Irrespective of the IOC operating the project, it is helpful to think of its CFC as typically having no employees other than its board of directors and officers.

Accordingly, the CFC usually depends upon the parent and affiliates for services associated with the property. If the CFC is the operator of that property, the JOA requires it to provide services for that property. These services relate to exploration, development and production activities, as well as day-to-day management, all of which are provided to the JOA by the parent/affiliates on behalf of the CFC. Managing the costs associ-
Transfer pricing

Diagram 2: Illustrative types of intercompany transactions and trade flows in the oil and gas industry

**Tangible Transactions**
- Sale/Purchase of hydrocarbons, refined products, and drilling & production equipment; Leasing/Chartering of equipment and other assets.

**Intangible Transactions**: Technology, Trademarks, Trade names, Processes

**Other Transactions**: Capital, Loans, Financial & Performance Guarantees

**Service Transactions**
- Engineering/Construction services, Operations/Logistics Services, Management and Administrative Services.

**Downstream**
- Refining & Distribution Company (Country D)

**Midstream**
- Transportation Company (Country C)

**Upstream**
- E & P Company (Country C)
- Oil Field Services Company (Country A)

**Common transfer pricing issues in the industry**

With so many intercompany transactions taking place in the O&G industry, and the value of these transactions, tax authorities and taxpayers around the globe are increasingly at odds about what is an arm’s-length price for related party transactions. The following sections discuss some of the transfer pricing issues that are often encountered by industry participants.
Commodity transactions (oil, gas and refined products)

Historically, E&P companies and other industry participants have sold hydrocarbons to related parties based on well-established indices, such as NYMEX prices, and treated these indices as comparable uncontrolled prices for transfer pricing purposes. This method of pricing intercompany commodity transactions has been treated as sacrosanct by taxpayers and tax advisers alike. This intercompany pricing practice has recently come under scrutiny by taxing authorities (including some US state revenue authorities). The two types of approaches we have seen tax authorities use on commodity transactions are either to ignore the comparable uncontrolled prices and benchmark the distribution return using a broad set of wholesale distributors of all sorts of products, or to reject the differential adjustments made to the indices to account for shipping, location, quality, volume, and other factors the taxpayer uses to increase comparability. Because of the volume of these transactions, such adjustments can create large transfer pricing adjustments.

Take for example an intercompany sale of one million barrels of Venezuelan heavy crude priced on NYMEX settlements of West Texas Intermediate minus a quality differential of $14.50. The intercompany price would be the NYMEX price minus $14.50 per barrel. If a tax authority rejects the differential, the transfer pricing adjustment on this single transaction would total $14.5 million. Similarly, because wholesale hydrocarbon distribution margins are thin and difficult to find comparables for, large transfer pricing adjustments could be seen from application of profit based methods, such as the comparable profits method or transactional net margin method. Identifying stand-alone refineries for benchmarking purposes is equally difficult.

The arm’s-length nature of commodity transactions can be justified by demonstrating that the taxpayer has contracts with third parties with similar pricing and terms, that the differentials are market based, and that the index pricing is imbedded in the company’s financial systems and therefore less prone to manipulation. The consolidation of commodity trading and hedging activities with the associated de-risking of downstream entities can also reduce the pressure on the intercompany commodity pricing, although tax authorities may view trading operations as routine services in the absence of sufficient substance and capital at risk.

Services

There is a plethora of intercompany services that are provided within the O&G industry. These services range from the provision of engineering and technical services to and on behalf of a related party, to management, administrative, and other operations related services provided by the corporate headquarters of industry participants. Services transactions are analyzed by identifying the total costs, including employee stock options (ESO) and bonuses, associated with the services provided, and determining which activities provide benefit to service recipients. Typically, the costs associated with value added activities are charged to service recipients with some profit element, while all other non-beneficial costs are determined to be either pass-through expenses, or stewardship (or shareholder) related costs. These costs are then allocated to service recipients using an appropriate allocation method. As a result of uncertainty between what is classified as beneficial activity and what is not, tax authorities are increasingly challenging deductions on expenses arising from intercompany services, demanding additional evidence (such as phone/travel receipts, time sheets, task deliverables, etc.) of actual services or increasing the markup on outbound services transactions. The US Internal Revenue Service’s (IRS) position on the pricing of engineering and technical services in the O&G industry in particular, appears to be evolving. The types of arrangements under which intercompany services are provided within the O&G industry are not only unique but significant in terms of value. A big E&P company may provide more than $1 billion of intercompany services to affiliates annually. Industry participants often provide the same types of services at cost (or cost plus a small markup) to their related parties and third-party joint venture partners in the context of a JOA or PSC. The pricing to third parties has often been treated as comparable uncontrolled service prices (CUSPs) to determine related party pricing. However, in the US, the use of CUSP in analysing such transactions has been challenged in some cases, as the IRS has relied on the services regulations promulgated under Treas. Reg. § 1.482-9 to compel O&G companies to include both stock option expenses and a profit element in their charges to affiliates, irrespective of whether foreign tax authorities, joint venture partners, or NOCs will accept such charges. At times, the markups required on audit have been very large.

Where the IRS is headed next, however, seems to be an industry specific approach to intercompany services charges that could have significant implications for the O&G sector. It is understood, for instance, that the newly created IRS Large Business and International division is pursuing several industry pilot programmes with a goal to develop policies on the treatment of specific tax and transfer pricing issues, one of which is focused on intercompany services and intangibles in the O&G sector. It is not entirely clear what types of intangibles the IRS is trying to remunerate in this approach. O&G companies clearly employ processes, know how, and technologies to find and produce hydrocarbons. Indeed, the use of new approaches in the discovery and development of oil fields is an industry hallmark and have been exemplified overtime, as geopolitical events and the decline of easily reachable reservoirs are forcing the industry to explore in unconventional places.

The IRS’s position in this regard appears to suggest that US based engineers and scientists working for E&P companies produce value at well sites in remote places such as the North Sea and West Africa by combining their expertise with US
Transfer pricing

developed intangibles. The US and OECD transfer pricing regimes accommodates a range of approaches for dealing with the issue. Depending on the characterisation of the transaction, a taxpayer can elect to classify it as a complex engineering service, or a service bundled with intangible property.

Intangible property
The distinction between the provision of a service and the provision of a service bundled with an intangible is somewhat nebulous, especially in the O&G industry. To break this conundrum, it is important to consider whether there is anything proprietary associated with the service, whether the recipient is obligated to employ the results of such services, and if a manual or any other device that “has substantial value independent of the services of any individual” accompanies the services.

Industry participants and transfer pricing professionals are generally familiar with charges between related and unrelated parties for intangibles such as patents, trademarks, technology and know-how. Often, intangible property that is utilized in the related party context (such as patented manufacturing processes) can be licensed for a royalty payment that is benchmarked with either internal or external comparable uncontrolled transactions (CUT) using publically available license agreements. However, while transfer pricing methods for IP transactions are well developed, applying such methods in the upstream O&G sector can create certain complications. Intangibles used by E&P companies have often been developed in tandem with petroleum engineers and geoscientists at major universities, industry consortia and oilfield services firms. These non-proprietary assets are shared freely, in certain cases, with joint venture partners and NOCs in the quest for hydrocarbons, typically on a royalty-free basis. Due to this ambiguity of ownership and the openness by the industry to share knowhow, best practices and technology, allocating a price to this expertise may remain convoluted.

Further complicating intercompany IP valuations is the fact that there are so many different services, process and intangible assets coming together at the well site to produce hydrocarbons. Few of these assets are significant on a standalone basis; it is therefore difficult to value their separate contributions. In other industries, a royalty payment for the value of the IP would be paid in an effort to appropriately compen-
sate the IP owner; in the O&G sector, bifurcating the revenue stream from the sale of the resulting hydrocarbons between the amount resulting from the use of the IP (be it a tool, technique, process or patent) and that associated with more routine contributions is very difficult because of the complications, and where the delivery of certain services involve an IP component, some E&P companies and oilfield services companies have chosen to pursue expansive, multiparty cost sharing arrangements (CSA), whereby all legal entities share in the cost of intangible development and are allowed the use of the resulting IP on a royalty-free basis.

Before joining Deloitte, Randy spent more than 10 years as an international tax/transfer pricing executive for a Fortune 500 multinational company where he developed, implemented, and ultimately defended multiple transfer pricing transactions from the Internal Revenue Service exam phase through appeals. In addition, he has experience with transfer pricing planning and controversy matters in multiple jurisdictions outside of the US. Given Randy’s experiences both within industry and Deloitte Tax, he provides the key practical and technical transfer pricing skills that clients’ appreciate in today’s complex transfer pricing environment.

Randy Price is the leader of Deloitte Tax’s transfer pricing practice for the Houston office. His transfer pricing practice involves client projects spanning the entire energy value chain. Randy’s primary area of focus is helping energy related clients address global transfer pricing planning, documentation, and tax controversy matters. In addition to his core energy related experience, he has significant experience with transfer pricing issues involving the cost sharing of intangibles and related buy-in payments for technology focused industries.

John Wells is the mid-America leader of Deloitte’s US transfer pricing practice and the US energy sector leader. He is experienced in managing large projects involving quantitative analysis in the areas of transfer pricing and intangible valuation. Although his primary focus has been on the energy sector, Wells has provided services to clients across the industry spectrum, including Fortune 500 companies in chemicals, engineering, manufacturing, retail, software, and telecommunications.

Before joining Deloitte, Wells was the lead economist for the global energy and national resources sector of another big four firm, and an economic adviser to the Kuwait government. Wells was also a professor at Auburn University, where he taught PhD-level courses in time-series analysis, macroeconomics, and international finance. He has numerous publications and was a referee for the American Economic Review, Economic Inquiry, and other journals. Wells was awarded a National Science Foundation grant for his work on the effects of political events on financial markets.

Another potential approach to this transaction is to characterise the transfer of intangibles as a sale of the pre-existing IP to future owners of the IP, and characterise future development activities and costs incurred by the parties to the sales agreement as the provision of services. The sale of pre-existing IP could be analysed under Treas. Reg. § 1.482-4, while the provision of services related to IDC could be analysed under Treas. Reg. § 1.482-9. These services/IDCs could be allocated to the parties to the sales agreement at cost plus a profit element depending on the classification of particular activities related to the intangible development activities.

Centralised leasing

Significant leasing activity occurs in the O&G industry between related parties and between market participants. Benchmarking the price of leasing oil rigs, drilling equipment and vessels can be problematic if there are no strong external or internal comparable leasing arrangements (which seldom exist). One common approach to analysing this transaction has been to determine the arm’s-length lease rate received by equipment owners as the price that permits the equipment owner to earn cash flow at least equal to its cost of capital after expenses and income taxes over the lifetime of the equipment, where the cash flow has been discounted by comparable equipment owner’ cost of capital. Another typical approach is to benchmark the routine return earned on other functions performed by lessees, and allocate the residual profit to the equipment owner. However, these approaches may not overlap and may not be foolproof depending on the type of equipment under lease.
Footnotes

1 Hourly consumption of oil is based on conversion of annual consumption of oil from International Energy Agency, http://omrpublic.iea.org/

2 Securities and Exchange Commission Form 10-K of Super Major oil companies.


4 Bureau of Labor Statistics data, March 2012, oil and gas extraction and support activities for oil and gas operations.

5 Specifically, the U.S. shale play has been encouraged by an abundance of drilling equipment and open-access pipelines, which have facilitated wildcard exploration in multiple locations, and strong property rights, which bequeath landowners with mineral rights and economic incentives to exploit their holdings. Shale of the Century, The Economist, June 2, 2012.


8 The conditions ideal for oil and gas formation are between 180 and 450 degrees Fahrenheit and depths of 7,000 to 25,000 feet, with more gas than oil being produced at higher temperatures and pressure. If temperatures or pressure rise too high, the organic material decomposes to carbon dioxide and water. Oil and Gas Production, Martin Raymond and William Leffler, PennWell, 2006.

9 A geologist is a scientist who studies the earth by examining rocks and interpreting their history. A geophysicist is trained in physics and mathematics to study the subsurface using gravity, magnetic and seismic readings.

10 Brazil’s oil boom, The Economist, November 5, 2011.


12 Critical issues and drilling & completions, Drilling Contractor, January/February 2011 and January/February 2012.

13 Spears & Associates, Inc.


16 The NAICS related party data is sourced from The U.S. Census Bureau: http://sasweb.ssd.census.gov/relatedparty/ Related party trade includes import transactions between parties with various types of relationships including "any person directly or indirectly, owning, controlling or holding power to vote, 6 percent of the outstanding voting stock or shares of any organization," and related-party export transaction is one between a U.S. exporter and a foreign consignee, where either party owns, directly or indirectly, 10 percent or more of the other party.

17 The oil and gas industry in Table 2 is defined as a combination of NAICS code 211 — Oil and Gas Extraction, 324110 — Petroleum Refinery Products, and 333132 — Oil and Gas Field Machinery and Equipment Manufacturing.

18 A JOA in the O&G context is a legal document which irrevocably vests in some person or persons, acting in a representative capacity, the authority to extract and sell O&G for the joint account of two or more partners. Model JOAs are provided by the Association of International Petroleum Negotiators; http://www.aipn.org/modelagreements/. PSCs govern the contractual relationship between a national government or NOC and the E&P companies working the property.


20 It is important to note that market prices for natural gas are determined regionally, unlike oil prices which are determined in a global context. European gas prices are often tied to the price of oil due to long term contracts with Russian and Norwegian exporters.

21 LMSB Restructuring to Strengthen International Tax Compliance, IRS Says, BNA Daily Tax Report August 5, 2010

22 Treas. Reg. § 1.482-4(b). See also the draft OECD Guidelines Chapter VI, which indicate that an intangible must be capable of being owned or controlled for use in commercial transactions and may be used in connection with a service without an actual transfer of the intangible occurring.

23 Under a CSA, two (or more) related companies agree to share future risks and costs associated with R&D of new technology to be used by each participant in their respective territories, in proportion to reasonable anticipated benefits in future. However, if future R&D is expected to build on current technology developed by one of the companies, the other cost sharing participants must buy-in. Treas. Reg. § 1.482-7(c) calls the payment for such pre-existing technology Platform Contribution Transaction (“PCT”). After buying-in, the cost sharing participant will continue to participate in the development of subsequent technologies based on either the pre-existing technologies or brand new technologies. The intangible development costs (“IDC”) associated with these future technology developments is shared by participants in the CSA.
Transfer pricing in today’s shale plays

The shale industry is booming across the world with companies keen to exploit the rapid development in this sector. Randy Price, Nadim Rahman and John Wells of Deloitte explain that as the industry grows, transfer pricing will take centre stage, and offer insight on how effective tax planning and addressing the transfer pricing rules are crucial to managing risk.

The North American oil and gas industry is being transformed by technology advancements that have allowed natural gas, crude oil and other liquids to be economically extracted from shale resources. As part of the transformation, the industry is experiencing a substantial amount of mergers and acquisition (M&A) activity, which highlights certain international tax conundrums, primarily in the area of the transfer pricing. The paper discusses the shale revolution and then specifically examines potential approaches for addressing transfer pricing issues using different methods.

Recent developments
The US has been experiencing an energy revolution as new technological achievements have made the extraction of oil and gas from unconventional resources (such as shale gas and shale/tight oil) feasible. Analysts had been predicting since the 1990s that the US would become a significant importer of liquefied natural gas, but the development of shale gas plays in the US may have made the need for imports largely irrelevant, and have led to a situation where America could potentially even become an energy exporter in coming years. Initial focus of this industry was on the extraction of shale gas, but with depressed natural gas prices many have turned their attention to drilling in more profitable liquids-rich shale and tight oil formations. Independent oil and gas companies that were able to take advantage of previously high gas prices primarily pioneered the technologies and knowledge that have made this possible. However, the drop in gas prices that largely resulted from the new gas supplies has created both trauma and opportunity in this burgeoning industry. Some of the companies that initially benefited from the enormous benefits of the new technology now find it advantageous to take on partners or sell off parts of their operations. Eyeing opportunity, much larger integrated oil companies (IOCs) and national oil companies (NOCs) have been able to take advantage of this situation and have invested heavily in North American shale plays. But, the investment by these larger corporations in North American companies may lead to transfer pricing issues as they encounter the possibility of intercompany transactions relating to transfer of intangible property and provision of engineering services.

Shale reserves around the world
North America remains the epicentre for the shale industry globally. Initial estimates suggested that there is about 862 trillion cubic feet (tcf) of recoverable shale gas in the US, out of a global total of 6,622 tcf, although a recent estimate of the total amount of recoverable shale gas by the Energy Information Administration (EIA) reduced this to 482 tcf. As of 2010, American production of natural gas from shale resources reached 10 billion cubic feet per day, and is expected to grow continuously.
until it settles at a level that is about 400% higher. In 30 years, shale gas production is likely to equate to half of the US’ natural gas needs. This large-scale extraction of shale gas has resulted in a decoupling of natural gas prices with that of crude oil on a comparable British Thermal Units (BTU) basis.

In addition to shale gas, it is recognised that North America is also home to large deposits of shale/tight oil that can be economically extracted at today’s prices. Over the next 10 years, it is believed that shale oil will grow to about 20% of the US production, and could be over 30% by the year 2035. Due to this large increase in domestic production, the EIA forecasts that US imports of foreign crude oil will drop from 49% to 36% of domestic needs by 2035.

Outside North America, shale gas is believed to exist in many places across the world, with perhaps the most attention being focused on potential resources in China and Poland. In Europe, Poland has been a target for investment. Poland’s reserves are estimated to be among the largest in Europe. Development is already occurring and in June of 2010, Chevron Corporation announced it acquired rights to explore for gas resources in the Grabowiec concession, located in southeastern Poland. If successful, development of shale gas resources in Poland could supply much of Europe’s energy needs for many years to come.

The other major shale arena outside of Europe is China. China’s reserves of shale gas are thought to be one of the largest in the world, and are constantly being revised upward as continued exploration is undertaken. According to a 2011 EIA report, China possesses over 1,200 tcf of shale gas. To fuel China’s economy into the future, the Chinese Politburo has been encouraging Chinese NOCs to secure the necessary resources to ensure energy security. The three major Chinese NOCs, China National Petroleum Corporation, Sinopec Limited, and China National Offshore Oil Corporation (CNOOC) share a common set of parents: the former Ministry of Petroleum Industry and the former Ministry of Chemical Industry. In the early 1980s after China began instituting economic reforms, the Chinese government decided to convert the productive assets of these ministries into three state owned enterprises. These Chinese NOCs continue to dominate China’s energy sector. China has traditionally relied on coal as its principal source of power for its economy, but the pollution from this resource has created strong motivation to shift towards an alternative source of fuel. Through joint ventures with American companies operating in shale plays, China is now gaining the necessary know-how, and CNOOC started drilling its first shale gas project in China during early 2012.

**Technology**

The important technologies for the extraction of oil and gas from shale and tight oil formations include horizontal-well drilling combined with hydraulic fracturing, as well as various continuous enhancements to these techniques. Hydraulic fracturing has been employed by America for the past several decades. An estimated 35,000 wells are hydraulically fractured annually and it is estimated that over one million wells have been fractured since the forties. With respect to shale, hydraulic fracturing and horizontal drilling have grown exponentially, and in Texas’ Eagle Ford shale play, the amount of drilling permits granted have gone from 94 in 2009 to 2,828 in 2011.

Another important component of technology used to extract oil and gas from shale formations relates to water and potential environmental hazards. Hydraulic fracturing uses between one and 12 barrels of water for every barrel of shale oil that is extracted. Mitigating the threat to water supplies and reducing the level of water consumption by unconventional methods are both regarded as major priorities in the industry. The Government Accountability Office (GAO) reported that if the industry could manage to extract shale oil at a level that consumes only one barrel of water for every barrel of oil, the industry could sustain a level of production equal to 2.5 million barrels a day based on water rights. While we have discussed these technologies, there is an additional component that needs to be considered in this section. These aforementioned technologies are mainly embodied in machinery and equipment, but what makes them useful is qualified professionals who can bring these technologies to life. The technical skills involved in operating advanced equipment and applying abstract techniques occupy a grey area between a simple service and an intangible offering from a transfer pricing perspective. These skills are arguably services, but they are so intermeshed with the technology in question that these transactions might be characterised in different fashions.

**Mergers and acquisitions**

There are many reasons that larger companies would seek to invest in the shale industry in spite of current prices, and this primarily relates to economics and technology. Prices have fluctuated considerably in recent years with natural gas peaking at $13.69 per million British thermal units (MMBTU) in 2008 that then crashed and helped to precipitate considerable M&A activity. At the end of February in 2012, the Henry Hub price of natural gas for April contracts was $2.616 per MMBTU. Energy consultants at Deloitte have found that in 2010 there was $53.4 billion in shale related acquisitions in North America, and this number grew to $63.6 billion in 2011. While large US companies were the dominant players with respect to acquisitions in 2010, by 2011 nearly half of the value in acquisitions came from Asia.

In addition to the belief that energy prices will continue to rise in coming years as the global economic recovery progresses, both IOCs and NOCs are looking to acquire some of the more sophisticated technological know-how that primarily independent oil and gas companies in the American
shale plays pioneered. Viewing opportunities in Europe and Asia, there is substantial room for international expansion, which makes the technological know-how even more valuable. These technologies can be acquired through outright acquisitions, but also through joint-ventures. Chinese NOCs commonly require a technology transfer in exchange for investment, and this allows them to acquire technology for their own purposes.

Common investment structures and tax considerations

**Inbound — joint-ventures**

Joint ventures, like many others inbound investments, may affect the tax status of the associated or affiliated entities, and open the door to transfer pricing issues in relation to intangibles or other cross-border transactions. When a company participates in a joint venture, the first consideration for transfer pricing is control. According to the US Treasury Regulations Section 1.482-1(i)(4) (Treas. Reg. § 1.482-1(i)(4)), “control” means any kind of control, direct or indirect, whether legally enforceable or not, and however exercisable or exercised, including control resulting from the actions of two or more taxpayers acting in concert or with a common goal or purpose. It is the reality of the control that is decisive, not its form or the mode of its exercise. A presumption of control arises if income or deductions have been arbitrarily shifted. The notion of control is rather vague, but should be taken into substantive consideration when dealing with inbound investment transactions. Depending upon the degree of control in a joint venture, a foreign NOC or IOC could potentially have a transfer pricing issue at hand, in which case they would need to make sure that this transaction is arm’s length.

**Inbound — acquisitions and new legal entities**

As Chinese NOCs and foreign IOCs want to gain access to shale-related assets and develop a more sophisticated understanding of the technological know-how behind the extraction of shale based resources, they are likely to begin setting up legal entities within the U.S. These new entities, while separate from their parent firm are still under their control and constitute a textbook case for a situation that necessitates Treas. Reg. § 1.482 compliance. In other words, all transactions between these foreign NOCs and IOCs (and their affiliates) should be at arm’s length in order to deal with the possibility of a tax authority’s claim of the shifting of profits.

**Inbound — US branches and asset acquisitions**

If a foreign firm decides to acquire shale assets in the US, but does not elect to create an American corporate entity they may be operating in a US branch. This branch can be taxed on effectively connected income if the operation qualifies as a US trade or business. If a treaty applies, the foreign entity may be taxed on its income attributable to a permanent establishment (PE). The PE threshold requires a significant presence in the US beyond mere preparatory acts, but maintenance of a place of business, branch, office, or an oil and gas well would likely constitute a PE. Additionally, the actions of an agent in the US who habitually exercises an authority to conclude contracts in the name of the foreign enterprise can create a PE for such enterprise. Once a foreign firm becomes a US taxpayer, the incentive may return to shift profits out of the US tax net, thus making it necessary to once again maintain that all transactions between these foreign NOCs and IOCs with their foreign branches be conducted in an arm’s-length fashion.
Outbound — US corporations operating abroad

All US corporations that control a foreign entity should conduct intercompany transactions on an arm’s-length basis. For example, if a US company develops or acquires oil and gas technology and the technology is used by a foreign affiliate, the foreign affiliate should pay an arm’s-length price for such use.

As a general matter, income of a US company’s foreign subsidiaries (controlled foreign corporations or CFC) is not subject to US tax, unless it is distributed or deemed distributed (repatriated) to the US parent. If profits of the foreign subsidiary are repatriated, then foreign taxes paid on those profits may be, subject to some restrictions, credited against US taxes. The ability to defer US taxation on un-repatriated foreign income can create an incentive to accumulate profits in the foreign subsidiary, if those profits are taxed at a lower rate than the US rate. Arm’s-length transfer pricing is therefore critical to determine that related parties conducting business transactions are recording the appropriate amount of revenue and cost.

In the context of a US corporation conducting operations in a foreign country through a branch (or PE), the same arm’s-length pricing considerations apply as discussed above with respect to inbound branches of foreign corporations. As a general matter, the US government may be somewhat indifferent when it comes to foreign branches. This is because the US utilises a worldwide tax system that does not permit deferral of foreign branch income. However, proper pricing of related-party transactions is still necessary. The US government requires a US taxpayer to use all valid means to reduce its foreign tax liabilities. A taxpayer is not permitted to sit passively by and pay foreign taxes that are not due, and then attempt to claim those foreign taxes as credits against its US tax.

The application of Treas. Reg. § 1.482

Arguably, the most relevant areas of transfer pricing with respect to recent developments in the shale industry relates to the processes used and the engineering services provided on an intercompany basis between affiliated companies. How you conduct the transfer pricing analysis is in many ways dependent on how you characterise these processes and engineering services in question. Questions such as whether a transaction is an engineering service under Treas. Reg. § 1.482-9 (Services Regulations), or the transfer of an intangible as processes under Treas. Reg. § 1.482-4 or Treas. Reg. § 1.482-7 are some of the significant issues in this area.

Interplay of licensing and services

When a company uses drilling equipment in the relatively warm and calm waters of the Gulf of Mexico, and simultaneously uses similar equipment in the harsh conditions of North Sea, the basic operating instructions come directly from the equipment manual. However, each drilling environment may require the operators to adapt to the specific drilling conditions that are present and these skills may be developed on site. And technical insights that are developed in each unique drilling environment may be viewed as specialised know-how that has value in its own right. Whether the company decides to classify this specialised know-how as a piece of intangible property or an engineering service is a matter of characterisation that does not have a bright-line test under the US tax regulations or OECD guidelines. US tax regulations define an intangible as an asset that has “substantial value independent of the services of any individual.” This language indicates that an employee using “know-how” in providing services to a related party does not necessarily transfer an intangible. In such a case, the know-how may be classified as a service and priced accordingly. However, if the employee reduces the knowledge to writing in the form of designs, formulas, processes, or other written forms, the Internal Revenue Service (IRS) might argue that a transfer of an intangible has occurred. This situation would then necessitate the determination of arm’s-length consideration for the intangible that might result in the payment of a royalty for the intangible in addition to the payment for the service itself if the intangible is a material component of the value exchange.

In the former case, the transaction could be classified as a service and companies in this situation could use Treas. Reg. § 1.482-9 for transfer pricing methods for services without having to be concerned about the transfer of an intangible. The transfer pricing of services allows for many methods similar to other sections in Treas. Reg. § 1.482, such as the comparable uncontrolled services price method, gross services margin method, cost of services plus method, comparable profits method (CPM), and the profit split method. Most often, the CPM is selected as the best method for a service-based transaction. In the case of engineering services, a markup will be necessary when applying the CPM method. The cost base of the markup is all-inclusive with respect to costs, and should include items such as stock based compensation and bonuses related to the personnel providing the service.

Services in joint operating agreements

Frequently in the exploration and production (E&P) sector, companies utilise joint operating agreements (JOA) when dealing with partners and this can affect the value of the service-related transfer price. The general terms of JOAs dictate that each entity with a working interest in a property will be entitled to production from this asset in proportion to its working interests. In addition, each investor must bear the expense of the operating services provided to the property in proportion to its working interest in the property. In the E&P sector, when a property becomes productive, the operator typically creates a division order relating to a contract to sell the oil or gas to third-party or related-party purchasers. The
The purchaser uses the division order as the basis for paying revenues to the interest owners, less applicable taxes. Typically, the expenses of these services are charged to the JOAs joint account at the cost of providing the services, with no profit element. The operator’s overhead expenses may be allocated and charged in different ways depending upon the terms of the JOA. The majority interest holders compensate IOC at cost for its services, with no profit element. For this reason, related parties within JOAs typically want to also charge out service transactions at cost to reflect market transactions. However, the Services Regulations issued by the IRS may require certain activities (such as engineering services) to include a profit element, which may challenge the JOAs use of cost as arm’s length.

Cost sharing of intangibles

For intangible property, a significant recent development has been the release of Treas. Reg. § 1.482-7 of the transfer pricing regulations in late 2011. Treas. Reg. § 1.482-7 deals with the concept of a cost sharing agreement (CSA) that allows for related parties to take a multilateral form of ownership for a piece of intangible property instead of one company licensing the intangible property to other related parties. In order for other parties to join the party of ownership of an intangible, they must make buy-ins known as a platform contribution transaction (PCT). The insight is that the existing intangible represents something of value and all future technologies should be derived from this initial intangible. The initial party should be rewarded for developing this intangible. After making the PCT, each participating party in the CSA will be in joint economic ownership of the platform intangible(s) and must continue to contribute to the costs of developing and maintaining the intangible property, known as the intangible development cost. All costs must be split according to the reasonably anticipated benefit received by the CSA participants inclusive of any stock based expenses or bonuses incurred.

Many large companies in the energy sector can use CSAs when managing their business operations and simultaneous-
Shale

NOCs and IOC investing in shale plays primarily for the sake of technology may find it desirable to implement a CSA. For engineering services under grandfathered CSAs (that is, CSAs in effect prior to the enactment of the new cost sharing regulations), the CSA participants should be aware that if shale technology could be differentiated enough from existing oil extraction technology that it might not be considered part of an existing platform and might result in the need for incremental consideration to the arm’s-length markup for the services transaction.

An alternative approach possible for this type of transaction could be to create a sale of the existing intangibles under Treas. Reg. § 1.482-4 and the cost of developing future intangibles is charged out under a services agreement under Treas. Reg. § 1.482-9. While this approach helps the transaction to potentially avoid the periodic adjustment regime of Treas. Reg. § 1.482-7, the commissioner still has the right to characterise a transaction as a CSA and make periodic adjustments for an open taxable year and for subsequent taxable years. Under this approach, these services should be evaluated under one of the methods prescribed under Treas. Reg. § 1.482-9 and would likely require a markup if the CPM is selected.

International relationships

The booming shale industry that started in the US has spawned a substantial amount of international joint ventures and acquisitions. These international relationships lead to situations where transactions must be considered arm’s length. Often, one of the main reasons for the acquisitions is for larger international corporations to gain access to intangible property. The primary concerns as far as Treas. Reg. § 1.482 is involved will relate to processes and engineering services. How these transactions are characterised could substantially affect a legal entity’s taxable income consequences, and will likely be a major area of continued IRS focus. As the shale revolution continues across the globe, transfer pricing will take centre stage in this rapidly expanding industry. Effective tax planning and addressing the transfer pricing rules is crucial to managing risk.

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Before joining Deloitte, Wells was the lead economist for the global energy and national resources sector of another big four firm, and an economic adviser to the Kuwait government. Wells was also a professor at Auburn University, where he taught PhD-level courses in time-series analysis, macroeconomics, and international finance. He has numerous publications and was a referee for the American Economic Review, Economic Inquiry, and other journals. Wells was awarded a National Science Foundation grant for his work on the effects of political events on financial markets.
Footnotes

4 Oil and Gas Reality Check 2012. A Look at the top 10 issues facing the oil sector. Deloitte Energy & Resources.
9 Oil and Gas Reality Check 2012. A Look at the top 10 issues facing the oil sector. Deloitte Energy & Resources.
18 These numbers were originally acquired from http://www.herold.com
20 Article 5 of the U.S. model tax treaty
21 Treas. Reg. § 1.482-4(b)
22 Treas. Reg. § 1.482-7(d)(3)
23 Certain types of tax issues can lead to the IRS’ attention given that there is a high-level of compliance risk. There are three tiers of compliance risk according to the IRS, and transfer pricing has a position in each of the top two tiers. The transaction in the 1st tier is the transfer pricing of intangibles, and the transaction in the 2nd tier is cost-sharing stock-based compensation. http://www.irs.gov/businesses/corporations/article/0,,id=200567,00.html
As energy firms discover and exploit new reserves which require significant amounts of financing, tax authorities have increased their focus on the intra-group financing transactions of such companies. Randy Price, Nadim Rahman and Bill Yohana of Deloitte investigate why the materiality of these transactions may have also increased taxation authority interest in the intra-group financing transactions of energy firms.

The arm’s-length principles for pricing their intra-group debt are complex in their application and are therefore difficult to comply with. One significant source of uncertainty regarding these transactions relates to the process for estimating the credit quality of a given project or business in a certain country. Estimating the credit risk associated with such transactions can be an involved exercise. A second source of uncertainty for taxpayers, but particularly for those in the energy sector, relates to how transfer pricing principles specifically should be applied to the pricing of intra-group debt.

The need for multi-billion dollar investment and the resulting transfer pricing issues

The oil and gas (O&G) industry is paramount to the movement of goods and capital, including human capital. The vast majority of transportable goods and associated logistics infrastructure is moved around and across economies and geographies primarily using the energy generated from either oil or gas. Tax authorities from both developed and emerging countries are trying to increase their knowledge and understanding regarding this global movement of goods and the associated profits.

Unlike many other industries, the O&G industry is a capital-intensive sector with a need for significant funding. Exploration and production (E&P) projects involve substantial capital investments with long-term contracts and relatively uncertain long-term returns. E&P companies engage in drilling and evaluation, along with completion and production. These activities can have time horizons from a few years up to a decade before a well may start to show a return and up to quarter of a century or more for the overall lifespan of some projects.

To receive the required financing, E&P companies may need to seek significant funding from a variety of resources. Some funding is extended through financial institutions that are sophisticated enough to evaluate the project risk and have the capital to manage the risk. E&P firms may also access the public bond market, the market for privately-placed debt, as well as more narrow markets for project finance. However, given the long time horizons for these projects, the difficulty in predicting recoverable reserves, the challenge in projecting revenues/profits, complexities/uncertainties of the analysis and inexperience of financial institutions to properly evaluate the risk, it is often the case that an E&P firm (or the E&P subsidiary of a larger concern) may experience significant costs in obtaining adequate project financing from third-party sources. Therefore, the local E&P affiliate (or its ultimate parent) may decide to secure a portion of its required financing from related entities within its group, including the parent company. Such transactions create potential transfer pricing considerations.
Determination of credit quality of the borrower

The credit quality of a borrower is a specific determinant of the interest rate of a loan or the yield on a bond issued by an E&P firm. However, credit analysts do not use uniform approaches to evaluate the credit quality of a given borrower in the E&P sector. While credit analysts might broadly rely on metrics relating to interest coverage, leverage, the quality and amount of reserves and the like, the emphasis placed by a credit analyst on each factor (and how each factor maps to a given credit quality) can vary.

Furthermore, when creditors look to fund O&G projects, they need to focus on the fact that these, especially those involving E&P, are long-term projects that will span over a decade, rather than using a typical one to two year financials projections, or extrapolating historical data to reflect future performance. When assessing a potential borrower’s credit quality, such data is adjusted to create a post-loan effect on the financials. However, for an E&P borrower, it is necessary to have reliable projections of the financial profile of the project over its lifetime.

Creditors typically adjust their interest rates to reflect the inherent risk in lending O&G companies such funds, and with the knowledge that, in certain instances, the borrower may not generate substantial revenue until they begin production of oil and/or gas. Thus, in determining credit ratings in the energy sector, some creditors might also account for the credit quality of the borrower, as well as any potential credit support that the legal borrower may receive from its ultimate parent and that corporate parent’s credit quality to determine what credit risk rating to grant the subsidiary. The potential for such adjustments raise various transfer pricing issues as to whether creditors should account for the fact that an O&G subsidiary is in fact part of a larger corporate group, which adds on to the existing inherent inaccuracy in determining the stand-alone credit quality of the borrower in this industry owing to the issue of steady-state point of view alluded to before.

The role of the OECD guidelines

Another specific source of uncertainty for E&P firms relates to available transfer pricing guidance – in other words, how a taxpayer or a taxation authority should attempt to evaluate a given transaction, particularly given that a credit analyst may account for the fact that a subsidiary is part of a larger group (even though it appears counter to arm’s-length principles to do so for transfer pricing purposes).

To better streamline transfer pricing regulations, the OECD has issued guidelines that are recommendations providing principles and standards for responsible business conduct for multinational corporations. Tax authorities throughout the world follow these guidelines and apply their principles to their own legislation (though how they do so may differ by country). In particular, the OECD guidelines are based upon an arm’s-length principle when dealing with intra-group transactions. The arm’s-length principle is designed to prevent income shifting between different taxing jurisdictions. The OECD guidelines, under article 9, paragraph 1, allow tax authorities to reserve the right to make the appropriate adjustments to the profits between two related enterprises to more accurately reflect a transaction that would have occurred between two unrelated parties. In particular, the OECD guidelines note:

[Where] conditions are made or imposed between the two [associated] enterprises in their commercial or financial relations, which differ from those which would be made between independent enterprises, then any profits which would, but for those conditions, have accrued to one of the enterprises, but, by reason of those conditions, have not so accrued, may be included in the profits of that enterprise and taxed accordingly.

This is especially important when considering how to evaluate credit risk in the context of multinational groups in the O&G industry. Financial transactions in the O&G industry, including intra-group loans and credit guarantee arrangements, allow O&G parent companies to finance their global businesses. However, the OECD has provided little specific guidance regarding how arm’s-length principles should be applied to intra-group financial transactions. This lack of concrete guidance has made it difficult for taxpayers to determine that they are appropriately applying the arm’s-length standard to their intra-group financial transactions and thereby managing their transfer pricing compliance and potential exposures. Taxation authorities have been adopting views inconsistent with one another regarding how intra-group financial transactions should be transfer priced by taxpayers. To make matters worse, individual authorities have not necessarily adopted consistent positions between their own taxpayer cases.

Separate entity versus group affiliation precept

Based upon the guidance in the OECD guidelines, taxation authorities, taxpayers, and tax advisers have broadly adopted two separate (and generally incompatible) approaches towards evaluating intra-group financial transactions. We describe these two approaches below.

Separate entity precept

Under the separate entity precept, for transfer pricing purposes, creditors analyse the credit risk profile for the loan solely based on the subsidiary’s risk profile, and do not take into consideration the parent company’s credit ratings or any contingent credit support that a member of a multinational group might provide to a related party. This approach might be argued with reference to how credit analysts might evaluate the credit quality of a borrower, how the OECD guidelines apply to a given financial transaction, or both. Some
argue that, unlike the contingent credit support precept, a subsidiary should be viewed as a separate entity from its parent corporation, and it is not appropriate to assign any credit enhancement to a subsidiary of a multinational, absent formal and legally binding credit support from the subsidiary’s parent. The creditor, when lending to the subsidiary as a separate entity, is taking on more of an inherent risk when the corporate parent is not involved in the transaction. Thus, the subsidiary should be charged a higher interest rate to compensate the lender for this inherent risk.

The tax authorities that have adopted the separate entity precept rely heavily on paragraph 1.3 of the OECD guidelines which indicates:

By seeking to adjust the profits by reference to the conditions which would have obtained between independent enterprises in comparable circumstances (i.e., in ‘comparable uncontrolled transactions’), the arm’s-length principle follows the approach of treating the members of a multinational enterprise (“MNE”) group as operating as separate entities rather than as inseparable parts of a single unified business.

Based upon this language, it would appear as though the OECD would prefer the separate entity precept; however, this language is found in the first paragraph of article 9 of the OECD Model Tax Convention, which defines transfer pricing concepts, in general. It does not specifically address the type of precept to apply when dealing with intra-group credit risk evaluations.

Group affiliation precept

Legally, a subsidiary is a separate legal entity from its parent. However, this does not deter some creditors from adjusting their credit evaluations of O&G subsidiaries based on the credit rating of their parent corporations. Creditors perform these adjustments to account for the fact that a parent corporation may provide credit support (as in, an implicit guarantee) to one of its subsidiaries even if they had no legal or explicit obligation to do so. Thus, this credit adjustment may reflect a situation in which a creditor analyzes the risk of the loan based on the subsidiaries’ corporate group affiliation.

Certain tax authorities argue that, because the market takes into account the credit quality of a broader multinational when considering the credit quality of a subsidiary, it is appropriate to do so within a transfer pricing context. For example, if the market lowers the subsidiary’s credit risk rating based on the assumption that the parent company will guarantee the debt, then it is reasonable for the parent corporation to also lower the credit risk, and thus the interest rate, when establishing an intra-group loan to its subsidiary.

In support of the group affiliation precept, many tax authorities consider the fact that the global reputation of the parent corporation can affect the subsidiary reputation in other foreign jurisdictions. Likewise, one subsidiary can affect the global credit rating of the entire group. For example, if a subsidiary in one jurisdiction defaults and the parent company fails to “bail” them out, since there is no contractual obligation to do so, this default can affect the perceived credit quality of other entities within the group. Similarly, if a subsidiary in a jurisdiction is responsible for environmental damages, it can reduce the entire group rating. Since no subsidiary is totally independent from its own group, some tax authorities deem it reasonable to adjust credit risk ratings of the group as a whole.

Incidental benefits and passive association

The transfer pricing of intra-group funding and the pricing of credit risk ratings represent differing points of view among tax authorities. Unfortunately, the OECD has provided very little guidance regarding how the arm’s-length principles should be applied to intra-group loans. Since the OECD has not offered any concrete guidance cross-border financial transactions have become a key risk area for major O&G companies.

What makes these issues even more prominent is the fact that the OECD has previously attempted to develop guidance

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**Biography**

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Randy Price is the leader of Deloitte Tax’s transfer pricing practice for the Houston office. His transfer pricing practice involves client projects spanning the entire energy value chain. Randy’s primary area of focus is helping energy related clients address global transfer pricing planning, documentation, and tax controversy matters. In addition to his core energy related experience, he has significant experience with transfer pricing issues involving the cost sharing of intangibles and related buy-in payments for technology focused industries.

Before joining Deloitte, Randy spent more than 10 years as an international tax/transfer pricing executive for a Fortune 500 multinational company where he developed, implemented, and ultimately defended multiple transfer pricing transactions from the Internal Revenue Service exam phase through appeals. In addition, he has experience with transfer pricing planning and controversy matters in multiple jurisdictions outside of the US. Given Randy’s experiences both within industry and Deloitte Tax, he provides the key practical and technical transfer pricing skills sets that clients’ appreciate in today’s complex transfer pricing environment.
specifically addressing intra-group loan financing issues, but it has failed to reach the consensus necessary to publish any relevant recommendations. During these negotiations, the OECD addressed benefits that naturally derive from being a member of a group:

… an associated enterprise should not be considered to receive an intra-group service when it obtains incidental benefits attributable solely to its being part of a larger concern, and not to any specific activity being performed. For example, no service would be received where an associated enterprise by reason of its affiliation alone has a credit-rating higher than it would if it were unaffiliated, but an intra-group service would usually exist where the higher credit rating were due to a guarantee by another group member, or where the enterprise benefitted from the group’s reputation deriving from global marketing and public relations campaigns. In this respect, passive association should be distinguished from active promotion of the MNE group’s attributes that positively enhances the profitmaking potential of particular members of the group. Each case must be determined according to its own facts and circumstances.

Since a contingent credit support is not attributed to any activity of the parent, it is not a service warranting compensation. Accordingly, the benefit derived from contingent credit support is to be subtracted from the transfer pricing of a loan. The US Treasury Regulations Section 1.482-9 stipulates that:

A controlled taxpayer generally will not be considered to obtain a benefit where that benefit results from the controlled taxpayer’s status as a member of a controlled group. A controlled taxpayer’s status as a member of a controlled group may, however, be taken into account for purposes of evaluating comparability between controlled and uncontrolled transactions.

This language indicates that the US will readjust credit risk valuations as though the subsidiary was not to receive contingent credit support from its parent company.

In addition, different tax authorities have been adopting views inconsistent from one another regarding how intra-group financial transaction should be transfer priced by taxpayers. O&G companies are also involved in O&G exploration activities in unsophisticated tax regimes, which have also not come to a conclusion on these issues; thus, mak-
Intra-group financing

ing implementation that much harder. These inconsistent views among tax authorities have just led to further confusion among O&G companies as to what guidance to follow, and potentially have increased their transfer pricing exposure.

Source of tax risk

Many tax authorities have recently been focused on the credit risk ratings of intra-group loan financing transactions, both in the O&G and other industries. The pricing of a loan impacts both the borrowing jurisdiction (in terms of the deductions that it can claim) and the lending jurisdiction (by virtue of the income that it receives.) Absent global consensus on this issue, combined with additional guidance that can be applied to financial transactions, we can expect this area within transfer pricing to remain a specific source of tax risk for multinationals and tax controversy.

The authors would like to thank Lani Payne, a consultant with Deloitte's global transfer pricing services, for her significant contributions in assisting with the research and drafting of this article.

Footnotes

1 OECD Guidelines, Art. 9, ¶ 1.6
2 OECD Guidelines, Art. 9, ¶ 7.9.
Global Transfer Pricing
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Multinational organizations are operating in an environment of unprecedented complexity. Rising volume and variety of intercompany transactions and transfer pricing regulations, accompanied by increased enforcement activities worldwide, have made transfer pricing a leading risk management issue for global businesses.

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Recent developments in the taxation of oil and gas in Brazil

While specific tax rules for Brazil’s oil & gas industry are still developing, it has not held up the amount of investment coming into the sector, explains Paulo Fernando Melo of Deloitte.

A fter the recovery of the major economies in 2010, some countries appear to be still restructuring their economy, specifically European countries at risk of default of public accounts. Meanwhile, at the end of 2011, the fear globally was that the US economy could enter recession because of the lack of growth in two successive quarters.

In Brazil, the continued growth of credit, employment, income, and maintenance of infrastructure investments announced by the government sustained the pace of growth of domestic consumption, which coupled with the recovery in demand from emerging countries, especially from China, led to a quick recovery and strong national economic growth in 2010.

Brazilian economic activity maintained its upward trend in 2011. In the last quarter of the year GDP growth of 4.2% over the previous quarter was recorded and annual growth reached 2.7% at the end of the year. Banco Central Do Brasil expects it to continue to grow at rates between 2.5% to 4.5% over the next five years.

The available data released in 2011 showed that Brazil’s economy was the same size as the UK’s, with the forecast for Brazil to become the 6th largest economy in the world by the end of 2012.

In 2011 the country produced 768 million barrels of oil in the 9,043 operational wells and 24 billion cubic meters (m³) of natural gas. In the last 10 years, the verified growth in Brazilian oil production was 45%, while natural gas production rose 55% according to the National Petroleum Agency (ANP).

With the recent discoveries of at least 50 billion and up to 100 billion barrels of oil on the pre-salt reservoirs, it is estimated that the country’s production will more than double over the next decade, which will lead the country to, at least, eighth in the rank of countries with the largest oil reservoirs.

In this situation, the new regulatory framework proposed by Brazilian government to control the pre-salt blocks is important for the world search for new oil resources. This justifies a closer analysis of such framework, especially regarding the tax impacts of the envisaged new production sharing agreement (PSA) model.

Potential tax impacts of the PSA model
From the first unsuccessful attempts to find oil onshore in the 19th century to the recent discovery of the world’s largest pre-salt reservoirs offshore, the oil and gas industry in Brazil has changed significantly and has achieved a new level of maturity.

Since 1997, oil and gas activities have been carried out via concession agreements under the Petroleum Law and regulated by a specific agency, the ANP. The concession agreement is based on the royalty/tax model, in which the concessionaire (that is, the oil company) is granted the right to explore for and produce oil and gas in return for bearing all costs and risks, including taxes related to the operation. Under
the concession agreement, the concessionaire is the exclusive owner of the production, upon payment of the applicable royalties and a special participation fee to the Brazilian government (in addition to other applicable fees and payments made to the government).

The bidding rounds to grant the right to explore for and produce oil and gas were guided solely by the concession model until the state-controlled company, Petróleo Brasileiro (Petrobras), discovered a large oil reservoir in the Tupi Field, located in a pre-salt (or sub-salt) area. As a result of this discovery, a new regulatory framework was introduced in 2010 to control the pre-salt blocks and any other area deemed to be strategic by the Brazilian government. However, the new regulatory framework was not extended to the blocks that were previously under a concession agreement. This new regulatory framework, based on the use of a PSA, will coexist with the existing regulatory framework of concession agreements.

Under the envisaged PSA framework, the oil company will bear all costs and risks of oil and gas exploration, evaluation, development, and production. If a commercial discovery is made, the oil company will be granted the right to recover costs and investments made with a share of the production, the right to the volume of production corresponding to the royalties due, as well as the right to a profitable return on investment through a predetermined percentage split.

Another relevant aspect of this new regulatory framework is the fact that Petrobras will be the operator of all pre-salt blocks via a minimum participation of 30% in a consortium to be entered into with private companies. Petrobras can also be directly contracted with by the Brazilian government without previous bidding. Though this provision is viewed as an imposition by the Brazilian government, most consortia in the oil and gas industry already have Petrobras as a partner, as illustrated in Chart 1.

Under the PSA model, Pre-Sal Petroleo (PPSA), a Brazilian company for management of oil and gas, created in 2010 by Law #12,304/10 will participate in the consortium. This new government-owned company will be responsible for the management of all production-sharing contracts and federal government oil and gas commercialisation contracts. And in 2010, Law #12,351/10 created a social fund for regional and social development in which revenues from pre-salt areas will be invested in programmes to combat poverty and address climate change, educational development, culture, public health, science, and technology.

From a tax perspective, Brazil still lacks specific income tax legislation for the upstream oil and gas industry, which is different from what is seen in most OECD oil and gas producing countries. For example, there is no ring-fence for upstream activities (Brazil instead taxes at an entity level).

**Regulatory uncertainty**

Since tax regulations are general, there is still uncertainty about the appropriate mechanism in the tax law for the depreciation and depletion of assets, including oil and gas-specific assets. As a result, procedures for depreciation and depletion vary across many upstream oil and gas companies in accordance with their tax attributes and interpretation of Brazilian tax legislation.

This issue already affects the upstream oil and gas companies in the concession model and may also have significant impacts on the upcoming PSAs for the pre-salt areas. So far, the new regulatory framework regulations have not clarified procedures for cost pooling in the PSAs, resulting in further uncertainty about how capital expenditures will have to be considered for purposes of cost recovery and profit oil determination.

In addition to the issues above, Brazil has a complex, indirect tax system, which also has a significant impact on capital
and operating expenditures (for example, through levies such as ICMS – state VAT-type tax, IPI – federal excise tax, PIS/COFINS – federal taxes on revenues, and ISS – municipal tax on services).

For tax purposes, the recovery of indirect tax credits depends on the nature of the transactions of the company and its tax attributes. For example, this is an issue for exporters because ICMS and PIS/COFINS are not levied on exports. Thus, exporters usually accumulate credits, which have limited possibilities for use or offset. And because of the lack of specific regulation, there are still uncertainties as to whether any indirect tax will apply to the PSA structure. In this context, the interaction between the PSA-specific regulations to be introduced for cost determinations and the complex indirect taxation in Brazil will present important questions. For example, will regulations acknowledge that ICMS may be a cost for exporters?

As outlined here, the details of the PSA regulations to be implemented will be essential to determining the economic impact of this new regulatory framework and the related tax implications. The Brazilian government did not debate the answers to these tax questions completely when it issued the respective legislation in 2010, so it should clarify its position.

Financial and tax challenge for multinationals
While answers to these highly complex questions are still being debated, the challenge for multinationals operating in Brazil will be to determine the financial and tax impact of operating under this regulatory framework when bidding for participations in the pre-salt areas under the new regulatory framework. On the other hand, from an economic perspective, both models (that is, concession and PSA) are not reducing the attractiveness of Brazilian oil and gas in practical terms. Several major oil companies continue to operate in the industry, as Brazil, an economically and politically stable country in comparison to other troubled areas around the globe, continues to demonstrate prolific discoveries. Therefore, even with some uncertainties and difficulties in the regulatory and tax framework, the major discoveries and flow of investment into the Brazilian oil and gas industry indicate that there is a greater potential for exploration in areas of all kinds (onshore fields, offshore shallow water, deep water and offshore pre-salt areas).

Footnotes
1 Pre-salt discoveries’ information is provided by Deloitte’s Petroleum Services Group. For the ranking positioning, information from International Energy Outlook 2011 was taken into consideration in which Brazil was ranked 17th country in reserves. With the new pre-salt discoveries, Brazil should be in the 8th position.
2 A pre-salt or sub-salt area forms a range of rock that stretches under an extensive layer of salt, which in certain areas of the coast is up to 2,000 meters thick. The term “sub” is used because these rocks were deposited before the salt layer. The total depth of these rocks, which is the distance between the surface of the sea and the oil reserves beneath the salt layer, can reach more than 7,000 meters.
3 The term “profit oil” can generally be defined as the amount of production, after deducting oil production allocated to costs and expenses that will be divided between the oil company and the Brazilian Government under the PSA.
4 In this context, “cost” can generally be defined as the portion of produced oil that the oil company applies on an annual basis to recover defined costs specified by the PSA.
An overview of taxation of oil and gas in China

Andrew Zhu and Amy Lo, of Deloitte in Beijing, analyse the tax trends in China’s oil and gas sector.

The oil and gas sector, an exciting yet complex industry, continues to undergo significant changes, such as technological development and resource discoveries.

For China, demand for energy in the past decade has surged with its fast economic growth. It has been known as a consuming black hole for energy imports all over the world.

Through its new twelfth five year economic development plan, China is on its way to changing that reputation to containment of importation and encouragement for domestic production with government planned investment in upstream oil and gas industry and energy infrastructure to meet the economy’s expanding energy demand.

This includes the building of a large scale oil and gas producing base and the development of the natural gas sector including shale gas. The Ministry of Land and Resources in China recently announced in February that China discovered 1.37 billion tonnes of proven geological oil reserves in 2011, up 20.6% from 2010.

This was the ninth year for China to see new oil reserves rise by more than 1 billion tonnes since the founding of the People’s Republic of China in 1949. New technically recoverable oil reserves totalled 266 million tonnes, up 21.4% from 2010.

China also discovered new reserves, a rise of 29.6% to reach 765.95 billion cubic metres (bcm), of proven geological natural gas deposits, and new technically recoverable gas deposits amounted to 395.69 bcm, up 37.6%.

Officials did not specify the country’s remaining proven oil and gas reserves that are technically recoverable or commercially viable and China has strict definitions in respect of expected production from oil fields over the life of a mine and often differs from the Western countries.

The Chinese government encourages, yet regulates and protects according to law, the cooperative exploration activities of foreign enterprises in the oil and gas industry. Foreign investments, for example Sino-foreign cooperative joint venture projects, Sino-foreign contractual joint venture projects, or wholly foreign-invested projects, in China’s extraction of petroleum and natural gas industry have been trending upwards with newly established projects from 2006 to 2009 based on published statistics.

Actual utilised foreign capital for newly established projects was up by 253.73% compared with 2008 and reached $188.75 million in 2009. There was only an increase of 25.73% in 2008. And by countries or regions that newly set up enterprises in China, such as the US or the Asian countries including Hong Kong, Macau, Taiwan, Japan, Philippines, Thailand, Malaysia, Singapore, Indonesia, and Korea, the actual utilised foreign capital was up by more than 200% in 2009, a significant increase compared with that of 2008 for the US and for the Asian countries.

There has also been a marked increase in Chinese outbound energy and resource investments in the past decade to endeavour sustained supply in the long term, with
a surge in Chinese outbound mergers and acquisitions activities in 2010, which softened somewhat in the first half of 2011 with investors exercising price discipline, but lower mid-market acquisitions continue to rise.

A recent increased focus on oil and gas, coal related and other energy deal activity is also seen and expected to increase, shifting away from outbound acquisitions in the mining sector that typically denominates overseas energy and resource investments.

While outbound activities into North America and Europe continue to rise and Australia remains steady, more investors in search of quality assets are also looking to other remote areas such as Mongolia, South America, or Africa to secure supply.

This article outlines this brief industry trend with the tax regimes in China focusing on the oil and gas industry, and the common forms of investment into China that are often part of the planning in mergers and acquisitions.

**Taxation in China**

An overview of the selective tax regimes in China applicable to the oil and gas industry are described below:

**Enterprise Income Tax**

All enterprises earning income within the territory of China are subject to an income tax rate of 25% on their taxable income, pursuant to the Enterprise Income Tax Law that came into effect on January 1, 2008.

Where a foreign enterprise was incorporated outside China, has establishment in China, and engages in production or business operations, that foreign enterprise is subject to income tax for income effectively connected with its establishment in China.

Taxable income is generally defined as its revenue less deductible expenses and/or tax losses. For oil and gas enterprises, deductible expenses may include reasonable production and operating expenses, tax amortization of exploration expenditures, tax amortization of development expenditures, and reasonable overheads. Certain investment incentives surrounding qualified research and development may be available.

**Value added tax (VAT)**

A taxpayer that engages in the sale or importation of goods (goods include machinery or equipment as well as electricity, heat, gas), or provision of processing, repair, or replacement services within the territory of China, shall calculate VAT payable on the amount received from the sale of goods or taxable services by applying a given tax rate, generally at a standard rate of 17%.

Sino-foreign cooperative exploitation of crude oil and natural gas is subject to VAT at the applicable tax rate of 5% on gross sales. The VAT shall be paid in kind and the basis for computing such tax is generally the gross production after deducting the amount of oil used for operation and depletion. The Chinese party that participates in the cooperative is responsible for matters concerning declaration of VAT or applicable filings to the competent tax authorities.

**Consumption tax**

Consumption tax is generally levied on taxpayers who manufacture, import, sell, or commission the processing of taxable consumer goods within the territory of China.

Producers or importers may normally shift the tax burden to end-consumers although such tax is collected when goods were sold or imported. Taxable consumer goods are prescribed and include processed oils, which are specifically defined, such as diesel oil or taxable petrol that includes ethanol gasoline.

Processed oils that are produced by an oil producing enterprise but consumed as fuel or raw material during production are generally exempt from consumption tax effective from January 1, 2009, while consumption tax is still levied on processed oils for commercial sales.

A refund of consumption tax levied may be available effective from January 1, 2009, when (i) an oil/gas field enterprise

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**Biography**

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He has been actively involved in a variety of outbound and inbound projects serving multinational clients such as Chevron, BP and Hess, as well as many state-owned enterprises such as CNPC, CNOOC, and Sinochem.

Andrew has extensive experience on cross-border international mergers and acquisitions (M&A) tax matters, including tax structure optimisation, financing planning, disposition alternatives, PE fund structuring, initial public offerings-related tax services, and post-transaction integration services. He has also provided business and tax advisory and due diligence services for more than 100 M&A transactions in China and overseas.

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Enterprises that extract mineral products within the territory of China are liable to pay resource tax under the Provisional Regulations of Resource Tax made in 1993.

Mineral products include crude oil and natural gas. A reform of the oil and gas resource tax regime was undertaken in 2011, with the State Council issued amendments to the Provisional Regulations of Resource Tax (the new regulations), and to the regulations of Sino-foreign Cooperative Joint Ventures exploiting onshore and offshore oil resources.

A fundamental change is to base a levy on selling price rather than production volume of crude oil and natural gas, with tax rates ranging from 5% to 10%. A Sino-foreign Cooperative Joint Venture is a specific form of joint participation with a Chinese partner in exploitation, development, or production of resources in China and this will be further described under the next section titled “Investment into China”.

The reform was first progressively implemented with pilot schemes for specific regions and subsequently a nationwide rollout came into effect on November 1, 2011. A pilot scheme was first instituted specifically for Xinjiang with an effective date of June 1, 2010, and a tax rate of 5% levied on selling price of crude oil and natural gas.

The Chinese government in its effort to further develop the Western region then extended the pilot scheme, similarly with a tax rate of 5% levied on selling price of crude oil and natural gas but effective from December 1, 2010, to cover the entire Western region. This encompasses 12 western provinces and cities including Chongqing, Sichuan, Guizhou, Yunnan, Shaanxi, Gansu, Ningxia, Qinghai, Xinjiang, Inner Mongolia, Guangxi, and Hubei.

Under that pronouncement, Sino-foreign oil and gas exploitation projects located inside the China Western region that were signed before the effective date would still follow the existing mining royalty regime, which is described further in the next section. Those participating in projects entered into on or after that time will pay resource tax.

The oil and gas resource tax reform was finally rolled out nationwide for those other than the regions under previous pilot schemes, with an effective date of November 1, 2011, and tax rates ranging from 5% to 10% on selling price of crude oil and natural gas. Sino-foreign cooperative joint ventures exploiting oil and gas resources onshore or offshore will be subject to resource tax in lieu of the existing mining royalty from the same effective date.

There are certain preferential treatments for taxpayers under the resource tax regime and the pilot schemes, such as crude oil used for heating or maintenance of an oil well during exploitation will be exempt from resource tax, reduced rate for extraction of heavy oil, and tertiary oil recovery.

Resource tax is also not levied on crude oil and natural gas produced by taxpayers that are used by them in a continued production process, and a deem ing sales provision may apply if the self-use was for other purposes.

The resource tax reform was mainly for purposes of conserving resources and reducing negative environmental impact from mineral extractions, while some analysts believe this will also cause a larger portion of the profits from the resource companies to flow to the local governments.

Petroleum special profit tax
All enterprises (both domestic and foreign) that produce or extract crude oil from the territorial land or water of China and then sell this crude oil, whether within or outside of China, shall be subject to Petroleum Special Profit Tax. This
tax was first launched in 2006 as part of a series of government measures to rationalize the pricing mechanism of petroleum and its products.

The Petroleum Special Profit Tax is levied when the monthly weighted-average price of crude oil sold exceeds $40 per barrel. And effective from November 1 2011, the Ministry of Finance has raised the exemption threshold of Petroleum Special Profits Tax from $40 per barrel to $55 per barrel.

This change in exemption threshold came about due to economic changes including rising oil cost. The reform of the resource tax regime, which is described above and also came into effect on November 1 2011, has facilitated this adjustment to potentially offset additional tax burden of oil enterprises.

Various progressive tax rates ranging from 20% to 40% that correspond with crude oil prices are specified. Essentially, the amount of levy per barrel is calculated as taking monthly weighted-average price per barrel sold, minus $55, multiplied by the applicable tax rate and minus a shortcut calculation deduction. The levy is calculated monthly and settled quarterly.

The progressive tax rates and deductions are as follows:

<table>
<thead>
<tr>
<th>Crude oil price ($/barrel)</th>
<th>Tax rates</th>
<th>Shortcut calculation deduction ($/barrel)</th>
</tr>
</thead>
<tbody>
<tr>
<td>55 – 60 (inclusive)</td>
<td>20%</td>
<td>0</td>
</tr>
<tr>
<td>60 – 65 (inclusive)</td>
<td>25%</td>
<td>0.25</td>
</tr>
<tr>
<td>65 – 70 (inclusive)</td>
<td>30%</td>
<td>0.75</td>
</tr>
<tr>
<td>70 – 75 (inclusive)</td>
<td>35%</td>
<td>1.5</td>
</tr>
<tr>
<td>Above 75</td>
<td>40%</td>
<td>2.5</td>
</tr>
</tbody>
</table>

**Royalty for crude oil and natural gas**

A petroleum royalty is generally calculated at progressive rates ranging from 2% for annual gross production (AGP) of over 0.5 million tonnes, to 12.5% for AGP over 4 million tonnes, on a block-by-block-basis.

The royalty is paid in kind with the crude oil produced, and is based on the volume of annual production after deducting the volume of oil used in operation and depletion.

Sino-foreign onshore and offshore petroleum operations may be exempt from royalties, for example, companies whose annual production of crude oil is less than 500,000 tonnes located in provinces other than Qinghai, Tibet, and Xinjiang. A similar royalty mechanism is applicable on annual output of natural gas.

**Withholding tax and tax treaties**

Withholding tax rates on passive income such as dividends, interest and royalties are 10% in China.

China has over 90 tax treaties concluded with foreign countries and depending on the particular treaty countries, withholding tax rates may be reduced and can vary between 5% and 10% for dividends, between 7% and 10% for interest, and between 5% and 10% for royalties.

**Investment into China**

Inbound investments in the energy and resource sector would commonly take the form of either a joint venture (JV) or similar to a branch with permanent establishment (PE) in China due to certain restrictions on foreign investments in the sector.

Investment in oil and gas exploration and production (E&P) is commonly structured through a contractual joint venture (CJV) with a Chinese partner. The Chinese partner is normally one of the three major national oil companies (NOCs) in China, who would own the E&P right of the oil fields. The foreign international oil companies (IOCs) would enter into a product sharing contract (PSC) with the Chinese NOC by contributing the operating fund, equipment, and modern science for its share of oil sharing.

In China, CJV can be either a legal entity or not. In most cases for the energy and resource sector, the CJV is structured as a non-legal entity, under which the NOC and IOC operate under the same name, but prepare financial statements and file tax returns separately.

In this regard, the IOC may need to have its own accounting and tax personnel in China in order to comply with the relevant regulations.

In cases where the CJV is structured as a non-legal entity, it is similar to a branch with permanent establishment as the IOC operates in China. There should generally be no tax implications when the CJV repatriates profit back to the IOC as China does not impose branch tax under the prevailing tax rules.

However, when the IOC transfers its interest in the PSC to another party, gain, if any, is taxable in China.

There were some controversies on the applicable tax arising from a transfer of economic interest in PSC. Some believed that this was comparable to a situation where a foreign entity transfers its permanent establishment in China and therefore is liable for capital gain tax taxed at 10%.

While others considered that under a PSC, the exploitation cost and development cost are deducted for Enterprise Income Tax purposes, so it is closer to business profits, which are taxed at 25%. It appears from case discussions with competent tax authorities that the latter is likely the case for which transfer of an interest in PSC is taxed.

There are also restrictions on foreign investments in respect of oilfield services. For example, a foreign company is
not allowed to set up a wholly foreign-owned subsidiary in China engaging in drilling services.

Alternatively, it may have an equity joint venture (EJV) in China with a Chinese partner possessing the proper industry qualifications, or provide drilling services in China via PE on a project basis.

For an EJV, the upside is that the foreign company will be able to have a permanent presence in China through the form of a legal entity. The EJV will have its own brand name, local operations, local staff, and independent accounting and tax position.

The downside is whether the foreign company can find a Chinese partner with proper qualifications that is willing to be bound together in the long term or whether the EJV will have sufficient contracts/projects to be profitable.

A foreign company that is a party to a CJV may send its staff into China to operate a project as a subcontractor of the project owner. According to recent tax administration regulations, construction PEs in China are required to perform registration with the competent tax bureau after the service contract is signed. The tax bureau will monitor the performance of the activities of the construction PE via the registration record until the service is completed and the fee is settled.

Diagram 1 illustrates a typical example of a foreign oil field service company providing services in China via a PE. The major concerns related to the taxation of this construction PE would include:

- What portion would be treated as China-sourced income and attributable to the PE and thus subject to China Enterprise Income Tax; and
- The deemed profit rate to be assessed by the competent tax authority (ranges from 15% to 30%).

Holding regimes may be used when structuring acquisitions or investing in China, often from a tax-efficiency-planning and business structuring perspective.

Common holding regimes include Luxembourg and Singapore. When structuring with offshore holding companies, the taxpayer should be aware that the Chinese tax authority has focused on beneficial owner status when applying treaty benefits.

This should be looked at on a case-by-case basis and the central government has issued a circular, listing some factors which are adverse to the determination of an applicant’s status as a beneficial owner. In this regard, a pure conduit company lacking substance will likely not pass the beneficial owner test.

The Chinese tax authority also continues to target indirect transfer via intermediate companies registered in low-tax jurisdictions. Hence, use of an intermediary holding company for tax efficiency purposes that lacks substance may increase the risk of being audited or challenged by the Chinese tax authorities.

Transfer pricing

Transfer pricing in respect of related-party transactions should not be overlooked as China has issued and is aggressively implementing its comprehensive transfer pricing rules. The principal rule is that business transactions among related parties shall be priced at arm’s-length standard.

If the tax bureaus consider that the related parties fail to follow this principle, reasonable adjustments may be made by the following methods: the comparable uncontrolled price, resale price method, cost plus method, transactional net margin method, profit split method, and other methods that are consistent with the arm’s-length principle.

The concept of cost-sharing arrangements is present under the Enterprise Income Tax Law and taxpayers may apply for advance pricing agreements.

Trending upwards

Overall, Chinese outbound energy and resource investments will likely continue trending upward and expanding in scope and breadth. This evolving landscape along with China’s fast economic growth leads to continuous changes in regulations and tax rules, and businesses, whether domestic or foreign, should stay informed of the trend, adapt and be flexible to achieve success in China.
Footnotes


2 Caishui [2010] No. 98

3 Caishui [2011] No. 7

4 State Council Decree No 605, No. 606 and No. 607

5 Caishui [2010] No. 54 (Circular 54), Regulations on Several Issues of Crude Oil and Natural Gas Resources Tax Reform in Xinjiang.

6 Caishui [2010] No. 112 (Circular 112), Regulations on Several Issues of Crude Oil and Natural Gas Resources Tax Reform in Region.

7 Articles from Reuters (Beijing) dated October 10, 2011, “China resource tax reform to go national from Nov. 1” and from China Briefing (Magazine and Daily News Service) dated October 13, 2011, “China Kicks off National Resource Tax Reform”.

8 Circular Cai Qi [2011] No. 480 issued by the Ministry of Finance on December 29, 2011, effective from November 1, 2011.

9 But for a few exceptions, taxpayers with related-party transactions are required to prepare contemporaneous documentation, which is due either May 31 or June 20 depending on whether Guo Shui Fa [20009] No. 2 or Guo Shui Han [2009] No. 363 applies.

Russia is one of the major players in the world’s natural resources market. Alexander Krylov and Mikhail Sergienko of Deloitte provide an overview of key industry characteristics and players, consider recent legislative developments, and look at various business forms in the taxation of oil and gas activities.

**Key industry characteristics and players**

The Russian oil and gas sector is also characterised by a high share of state-controlled companies and tough administrative restrictions. The Russian oil complex is represented by nine large vertically-integrated oil companies and a number of smaller enterprises, which have an insignificant impact on total Russian oil production. Gazpromneft and Rosneft are state-controlled companies, which produce more than 30% of crude oil in Russia on aggregate. Russia’s other largest oil producers are companies such as Lukoil, TNK-BP, Surgutneftegaz, Tatneft, Slavneft, and Bashneft.

The key player in the gas industry is state-owned Gazprom, which controls more than 70% of Russian natural gas production. There are also several smaller independent companies such as Novatek, Itera, Nortgas, and others.

Historically there are three main strategic directions of Russian crude oil exports: Europe (such as Germany and the Netherlands), East (China and other Asia-Pacific countries), and North America. The European market is the largest importer of Russian crude oil and oil products with 80% share while crude oil deliveries to China and the US cumulatively amount to less than 20% exports share.

Though Russia’s proved oil reserves accounted for only 5.6% of the world’s total proved reserves (compared to Saudi Arabia’s 19.1%) at the end of 2010, it is expected that considerable additional reserves are located offshore and in the less-explored areas of Eastern Siberia.

The Russian government has recently been paying specific attention to offshore reserves and is attempting to stimulate its development, including development of related tax legislation.

**Legislative developments & investment environment**

According to the Order of the government of the Russian Federation dated April 12 2012, with an aim to strengthen the strategic positions of Russia in the world’s resources industry and to increase the investment attractiveness of new projects located offshore, Russian ministries should introduce their proposals (including draft laws until October 1 2012), with regard to the following. The offshore projects should be classified into four categories depending on technological difficulties, depth of the sea, and a number of other parameters. For example, offshore projects in Baltic Sea and Azov Sea will go to the first ‘easier’ category and projects in the Arctic Region will be in a fourth category of ‘difficulty’. Depending on the category mentioned above – the ad valorem rates of mineral extraction tax will be different and will gradually be reducing when applied to projects of higher difficulty. According to the Order, among other incentives planned to be developed are accelerated depreciation and an exemption from export customs duty for the companies involved in offshore extraction on excavated hydrocarbons. Certain other incentives are also proposed.
Overall, the investment environment in the industry remains challenging, due to the ineffective legislation framework and specifics of the Russian regulatory system. In addition, the government was reluctant to allow foreign majority control in the energy sector, especially in the projects developed at the Russian continental shelf. Significant exceptions have included the Sakhalin offshore projects.

The above mentioned Order can be an example of changes that the Russian government wants to introduce and it may be viewed as a positive sign from a tax standpoint. Several recent announcements about the leading US and European oil and gas companies stepping in to offshore projects via joint ventures with Russian companies supports this proposition of a changing landscape for this industry in Russia.

It is important to say that the legal framework with respect to use of subsoil in Russia was established by Federal Law ‘On Subsoil Resources’ on February 21 1992 (Subsoil Law). According to this law, geological surveys, exploration and extraction of minerals (including oil and gas) are performed under a licence for subsoil use. Such licence certifies the right of a subsoil user to perform certain activities on a certain part of subsoil within a limited period of time subject to compliance with the licensing conditions (usually established by a licence agreement, being an integral part of the licence). As a general rule, a licence for subsoil use is granted based on the results of an auction or tender.

The Subsoil Law provides for significant limitations when granting licences for subsoil use with respect to the parts of subsoil of “federal significance”, including the parts of subsoil containing the extractable reserves of oil of 70 million tonnes and more; containing the reserves of natural gas of 50 billion cubic metres and more; located in the internal waters, territorial sea, or continental shelf of the Russian Federation.

For the parts of subsoil of “federal significance”, the licence could be granted only to a Russian legal entity. Upon holding an auction/tender for granting the right to use such part of subsoil, the Russian government may also restrict participation in such auctions/tenders of Russian legal entities, which are owned by foreign investors in whole or in part.

For the parts of subsoil located at the continental shelf in whole or in part, the licence could be granted only to a Russian legal entity having the experience of working at continental shelf not less than five years and in which the Russian Federation directly or indirectly holds more than 50% of votes. In practice, this means that such licences could be granted only to state-owned oil and gas companies or, in some cases, to joint ventures with these companies (provided that the Russian Federation retains more than 50% of votes in the JV).

In most cases, foreign investors choose to obtain the licence for subsoil use in the name of a Russian subsidiary company. Still, for the parts of subsoil not falling within the category of “federal significance”, generally the licence could be obtained through a duly registered branch office of a foreign legal entity.

The above regulations are applicable only for companies which are directly engaged in geological surveys, exploration, and extraction of minerals. Service companies do not need to obtain the licence for subsoil use, though they may still need to obtain other licences to perform certain types of activities.

Business form and general tax issues
One of the initial stages of planning operations in Russia is choosing the most appropriate form of business presence. The possible options include creation of a Russian legal entity (either solely or as a joint venture with a Russian partner), opening a branch or representative office, tax registration of a mere separated subdivision, or performing activities through
joint activity agreements (simple partnership) with local partners. In most cases, foreign companies choose to operate through a branch office or a Russian legal entity. Foreign companies may also choose to operate in Russia directly without opening a branch office. In this case the foreign company should register a separated subdivision with the Russian tax authorities. Operations through such subdivision will not allow a foreign company to obtain any licences or permits for activities in Russia, including documentation required to authorise foreign personnel to work in Russia in most cases. Still, this option could be workable in certain situations, especially for short-term offshore projects performed by service providers.

As regards to operations through representative offices or joint activity agreements (JAA), these options are less popular and could be chosen only in certain specific cases. Formally, representative offices should not be directly engaged in business operations and their activity should be of non-commercial nature (such as marketing and information gathering). A JAA is not itself a legal entity but represents the pooling of assets for the common conduct of business. One of the partners is usually appointed as the party responsible for bookkeeping and statutory reporting.

A foreign investor may choose to enter the Russian oil and gas industry through acquisition of an existing oil and gas business. Such acquisition could be done through purchase of shares of an operating Russian company or through purchase of property complex required for the planned operations.

To perform certain types of activities in Russia a company may need a special licence or permit in accordance with Russian legislation. In most cases, such licences (permits) are issued by state authorities.

The licences for performance of certain types of activities may be required both for the users of subsoil (holding respective licence for the subsoil use and directly engaged in geological surveys, exploration, and extraction of minerals) and for service companies.

In some cases operations of a company engaged in oil and gas business may be structured in a way where activities requiring licence could be subcontracted to third parties holding such licences. In this case, the company may not need such licences itself.

In terms of financial reporting in Russia, for historical reasons, the Russian financial reporting framework has been determined and regulated by the state, rather than being developed by professional bodies. Indeed, the primary users of Russian statutory financial statements based on Russian Accounting Standards (RAS) are the tax and other state authorities, rather than management or third parties. Presently, international financial reporting standards (IFRS) are becoming increasingly important, both in terms of influencing the development of RAS and as the compulsory standards for certain types of Russian entities.

Significant progress is being made towards converging RAS with IFRS. During 2011, this trend was realised through new Russian standards on provisions, contingent assets and liabilities, segment reporting and cash flow statements coming into force, with new standards on inventory, fixed assets, employee benefits, and leases expected in 2012–2013.

New procedures for revising and adopting Russian standards will apply from 2013, including a requirement that they are based on the IFRS equivalent.

In terms of the taxation of oil and gas companies, the more important and significant taxes in this industry are corporate income tax (profits tax), VAT, mineral extraction tax (MET), excise tax, so-called personal taxes (personal income tax and social contributions), property tax, transport tax, and others.

At a cabinet meeting on May 2 2012, Russia’s government approved the 2013-2015 tax policy blueprint, which covers the major taxes mentioned above. Policy points must still go through the Russian parliament and may result in some draft laws; however, it highlights the major trends in the Russian tax legislation. Generally, the objectives of the Russian government were to promote innovation, eliminate ineffective programs, and increase incomes of the Russian budget.
Thus, it is anticipated that the level of mineral extraction tax on natural gas may increase, but it will depend now on the price of gas. Also, work will continue in the development of taxation mechanisms of mineral extraction based on the results of the financial and business performance of companies. This approach may change the application of MET and export duties and excise tax on oil products.

It is also very important to mention that after many years of discussion, new transfer pricing rules came into effect from 2012. The new rules are substantially based on the OECD Transfer Pricing Guidelines and it is therefore likely that both taxpayers and the tax authorities will rely on the practice and experience of countries with transfer pricing regimes based on similar principles.

More changes coming
There are a number of trends going on in Russia in terms of both oil and gas landscape and gradually evolving tax legislation related to the oil and gas industry. Some might comment that the developments in these two fields are slow, but that is only partly true. For example, lately tax legislation has begun to introduce international concepts in the area of financial reporting and transfer pricing; new proposals in taxation of offshore projects have appeared, tax incentives are being actively introduced, changes in customs legislation and the development of taxation mechanism in the area of mineral extraction have also emerged. It shows that it is a good start and one may anticipate more changes coming.
Recent developments in the taxation of oil and gas activities in the UK

Since its inception in the 1975, the UK North Sea tax regime has faced constant change. However with several welcome developments in the latest March Budget, oil and gas investors will hope that this marks a turning point and they will look forward with renewed confidence towards a period of stability of the tax regime.

**Recent industry developments**

After last year’s increase in the combined upstream corporate tax rate to 62%, some confidence in the UK North Sea appears to be returning. The most recent UK Continental Shelf (UKCS) 27th Licensing round attracted a record number of applications from a wide range of companies. While it is not known how many of these applications come backed with cash commitments, it is hoped that these applications will continue the recent trend of improving data (11 wells were drilled in the UKCS in Q1 of 2012 compared to nine for the same period a year ago, though still low compared to historical levels). This welcome news comes against a background of UKCS oil and gas production falling (18% and 22%, respectively), in 2011. Cost pressures in the North Sea have also been significant, with aging infrastructure increasing operations and maintenance costs and existing discoveries being more costly to develop. It is essential that exploration and appraisal continue to pick up if the remaining undiscovered reserves are to be found and future North Sea tax revenues secured.

The UK, like other countries around the world, faces a significant challenge in respect of its fiscal policy for North Sea oil and gas because of the desire by the government to extract a “fair” share of the economic benefit for the UK Exchequer being balanced against the incentives required to increase investment in what is now a mature oil and gas province (production peaked in 1999). This maturity has also led to a change in the balance of industry participants, with an increasing trend towards independent groups who are utilising technology to increase production from older fields, or are developing smaller fields. National oil companies have also been interested in the UK upstream sector because of open markets and the access to skills and knowledge that UK based companies bring. At the same time the interest of the oil majors is continuing to turn elsewhere, and given last year’s tax increases, the UK North Sea has slipped down the rankings in the international pecking order.

Upstream oil and gas taxation contributed about 20% of the corporate tax revenues in 2011 to the UK Exchequer. Once the indirect, employer, and other taxes are taken into account, the UK oil and gas sector plays an enormous part in the economy.

With oil prices staying around or above $100 a barrel, the dilemma faced by the government in recent years has been how to increase short-term oil and gas tax revenues, while maintaining investors’ interest in the sector to increase the overall recovery of hydrocarbons. It has been a tough balancing act and investor’s confidence may
The main foundations of the UK oil and gas fiscal regime that are still in place were laid in 1975 with the introduction of Petroleum Revenue Tax (PRT) and the corporation tax “ring fence”. These were designed to secure the Exchequer’s share of the benefit to be derived from oil and gas production on the UKCS. The rates of these taxes have fluctuated over the years but still remain in place today. In addition, many other North Sea taxes such as royalty, Advance PRT, and Supplementary Petroleum Duty have also come and gone. The regime has been far from stable with significant fluctuations in headline and effective tax rates.

PRT is a field-based tax on production profits charged at a rate of 50% (though as high as 75% in the past). PRT is now only applicable to fields where development consent was given before March 16 1993, which equates in principle to 100 fields, but in practice the majority (around 60 depending on the oil and prices) was never profitable enough to pay any PRT because of the available allowances and reliefs. Any PRT paid is deductible against a company’s combined ring fence corporation tax liability (corporation tax and the supplementary charge to corporation tax). One concern of investors has always been whether the tax could be abolished and the tax refunds on future decommissioning costs denied (PRT provides for an indefinite loss carry-back). One suggestion to address the uncertainty was allowing companies to “buy” themselves out of PRT, but as yet no firm legislative proposals have materialised, primarily because no agreement could be reached on the appropriate discount factors to be used. Now it appears that a contractual solution, first mooted in early 2010, will be implemented in respect of decommissioning costs (see below).

The corporation tax “ring fence” serves to segregate a company’s UK oil exploration and production from its other activities and subject them to a special tax rate and rules, such that losses arising outside the ring fence cannot be used to relieve UK oil production profits. Restrictions are also placed on financing costs that are allowed against those profits as these have to be for a qualifying purpose. The current rate of corporation tax for ring fenced profits is 30% (compared to a rate of 24% for non-ring fence profits from April 1 2012, onwards, and a stated intention to reduce this to 22% by 2014).

The Supplementary Charge to Tax (SCT) was introduced in 2002; levied at a rate of 10% on a company’s ring fence profits, and adjusted to treat finance costs as being non-deductible. As oil prices rose, the rate of SCT was doubled to 20% from 2006.

A further increase to 32% was introduced in 2011, which came as a major surprise to the industry. This increase was again made in response to rising oil prices, and funded a deferred increase in the level of fuel duty paid by motorists. The attempt by the government to link high global oil prices to high prices at the fuel pump attracted significant criticism, and did significant damage to the relationship between the industry and the government, though this has since improved. The government also made the commitment that if the oil prices fell below $75 a barrel on a sustained basis, they would reduce the SCT rate back down towards 20%. This is now a nonstatutory commitment linking the tax rate with the oil prices, with the trigger price being reviewed every three years, a feature more often seen internationally in field specific production sharing contracts. In addition, the rate of tax relief for expenditure on decommissioning was restricted to the previous SCT rate of 20%. This dislocation of tax rates applicable to income and expenditure has served to increase
Field allowances were originally introduced in 2009 to encourage new developments in respect of small fields, ultra heavy oil fields, or ultra-high pressure/high temperature fields. The allowances apply on a field-by-field basis by reducing the profits subject to the supplementary charge, potentially reducing the overall effective rate towards 30%. The scope of these allowances has been extended over time, with 2012 budget doubling the small field allowance and introducing a new field allowance to incentivise development of deep water fields to the west of Shetland. At £3 billion ($4.6 billion), this new field allowance will be the single largest field allowance in operation.

There is also consultation on possible extension to the existing field allowance legislation such that new “brown field” developments are brought within the rules, a change that is intended to maximise recovery of existing marginal projects and preserve existing infrastructure.

The wider range of field allowances is leading to an increasingly complex tax system, but more importantly, are moving towards a bespoke tax regime for individual projects.

Ring fence expenditure supplement

The Ring Fence Expenditure Supplement (RFES) is a relatively recent incentive to encourage new entrants to the UKCS. It is targeted at companies involved in exploration or development phase projects on the UKCS that do not yet have any UK taxable income against which to set their costs and tax depreciation. The RFES provides an uplift on qualifying costs, and the rate was recently increased from 6% to 10% from January 1 2012.

Decommissioning

A recent report by Deloitte’s Petroleum Services Group, with Douglas Westwood, has indicated that up to $48 billion may be spent on decommissioning in the UKCS through to 2041 on 273 platforms and nearly 6,500 wells, with a number of fields due to be decommissioned as early as 2020. This clearly represents a significant cost for the industry and the potential tax relief on these costs is large.

Changes in recent years to extend the scope of qualifying decommissioning expenditure and to extend the loss carryback rules for UK oil and gas companies mean that from a tax technical perspective many companies would expect to relieve most if not all of their decommissioning costs for tax purposes. It is now possible to carry back losses arising after the cessation of production as far back as April 1 2002 for corporation tax and SCT purposes, with an indefinite carryback for PRT.

However, for some companies such as the smaller independents and new entrants, this is less certain. Given joint and several liability for decommissioning costs between current and past field participators, and the risk that a field partner may not be able to fund their share of the decommissioning obligations, investors have been requiring companies to provide decommissioning security on a pre-tax basis (that is, for the gross cost of the decommissioning, without taking account of the tax relief). This has been driven by the fear that the government could renge on its share of the costs, for example, by abolition of PRT, or by restricting relief on decommissioning costs (as proposed in the current budget, where the relief is being cut to 50%). This requirement for pre-tax guarantee obligations has

Biography

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Roman is a tax partner in the energy, resources, and infrastructure group at Deloitte in London.

Having started in practice in 1993, Roman has spent his entire career working with oil and gas companies, as well as working with other parts of the energy value chain both in the UK and internationally. He is head of oil and gas tax at Deloitte UK, and was previously UK and global head of renewable energy. He has worked in practice throughout his career, and also spent a year in industry on secondment at Shell in 2004/05.

Roman studied politics, philosophy and economics at Keble College, Oxford.

He is a member of the Institute of Chartered Accountants in England and Wales, the Chartered Institute of Taxation and the Energy Institute.
tied up valuable capital that could be more productively used to reinvest in the UKCS and increase the recovery of hydrocarbons. At some point investors appeared to have lost confidence about the tax system stability and started looking to protect themselves against the downside risk.

Following extensive dialogue with industry over the last two years, the government announced in 2012 budget that it will introduce legislation in 2013, which will give it the power to enter into contracts with companies operating in the UK North Sea to provide certainty over the level of tax relief that will be available for the companies’ decommissioning expenditure. It is hoped that these measures will remove a major fiscal risk for investors in the UK North Sea. If companies are now able to move to post tax decommissioning guarantees, this should release significant funds for investment, which are otherwise tied up in letters of credit and commitments. The contractual solution represents industry’s preferred mechanism and the government is to be applauded for moving forward with this contractual solution. It promises to be a unique construct of a contract being used by the government to guarantee something that the government has power over (that is, the tax system), although some may believe that it reflects the proposition that investors have more faith in the Law Courts than the ability of the UK government to resist the temptation of changing the tax regime in its favour if the need arises.

International oil and gas operations

The UK, and in particular London and Aberdeen, remain a popular location for the headquarters of independent exploration and production groups with international oil and gas assets because of access to the capital markets and pool of technical, commercial and financial talent, and skills in the sector. The London Stock Exchange market continues to see a steady stream of new energy and resources listings. Some groups listed in London have maintained non-UK tax resident listed top holding company, which can bring practical challenges. However, recent changes to the UK tax system for UK holding companies means that there is now very little benefit from a corporation tax perspective from having a non-UK tax resident listed company.

The government’s aim is to make the UK the most competitive corporate tax system in the G20. The rate of corporation tax for non-oil and gas activities has been systematically reduced from 30% in 2007 to 24%, with further reductions announced to 22% by 2014. This is in conjunction with the introduction of a dividend exemption regime in 2009, the substantial shareholdings exemption for sales of shares in trading subsidiaries (introduced in 2002). The UK also has 119 double tax treaties, a branch exemption, no withholding tax on dividend payments, and an interest deduction for financing of UK and non-UK operations. The most recent improvements have been the changes to the controlled foreign company rules, which were seen as vital to reverse the trend of UK multinationals inverting their corporate structures such that they were no longer UK headquartered. There is evidence of this trend being reversed with some US based groups, including those in the oil field services sector, choosing to base their headquarters in the UK in the last few years.

Taxation of offshore activities

Non-residents involved in activities connected with oil and gas activities on the UKCS (such as exploration and production and related offshore services) have, subject to certain tax treaties, long been brought within UK tax net through rules which deem them to have a UK permanent establishment by extending the definition of the UK to include the UKCS.

However, the government announced in its 2012 budget that it will engage with industry on the taxation rights for non-oil and gas activities on the UKCS with a view to ensuring a level playing field for individuals and companies involved. This follows the introduction of powers to create Exclusive Economic Zones in 2009 to enable development of offshore wind and marine energy. At the moment, such activities do not fall within the scope of the extended definition of the UK, so would not fall within the scope of UK tax unless carried on by a UK tax resident company. This engagement is awaited with interest by many in the UK energy sector, but details are not yet forthcoming. If such activities were brought into the scope of UK tax, in many cases, the very high capital costs of such activities mean the activities would be loss-making for tax purposes initially. However, in some cases, for example offshore workers and related construction activities, changes to the regime are likely to lead to immediate additional tax being collected.

Looking ahead

The government and industry both hope that the decommissioning contract will bring some much needed stability and investment to the UK North Sea. The industry body, Oil and Gas UK, has suggested that up to £40 billion ($63 billion) of investment, postponement of decommissioning by five to seven years, and recovery of an additional 1.7 billion barrels of oil and gas could be unlocked through this if the changes provide the required certainty for investors.

The UK experience will also be watched with interest by other oil and gas jurisdictions particularly if the now promised fiscal stability and certainty can boost investment.

Companies will likely be hoping that the North Sea tax regime and investment climate are not disrupted by the economic and political challenges ahead, such as potential Scottish devolution. The issues for North Sea taxation presented by the Scottish question are many and significant, for example: Where would the line be drawn in relation to oil and gas tax revenues? Who would bear the cost of decommissioning tax refunds? How would the current North Sea fiscal regime be affected? Oil and gas companies around the world will closely watch the development of all of these areas.
Renewable energy is often synonymous in people’s minds with credits and incentives. However, there are two other critical tax issues facing renewable energy companies that can make or break an investment. Shannon Blankenship, Allison Easley and Christine Piar of Deloitte discuss how these tax issues can impact companies in this industry, some common situations, and identify areas for consideration and planning.

A renewable energy project typically starts with a development company that evaluates a site for energy potential, environmental impact, zoning, stakeholder approval and transmission. Assuming the site meets the requirements, the company will proceed with permitting, selecting suppliers, securing a power purchase agreement (PPA), purchasing equipment, and constructing the facility. The developer may either operate the facility itself or sell the constructed facility to an operating company, which will take over the PPA and operate the facility. Each decision along the way can have an impact on both a company’s transfer pricing and FIRPTA results.

Transfer pricing
Transfer pricing rules apply to all intercompany transactions. A common misconception is that only transactions that cross international tax jurisdictions are relevant. Because credits and incentives play such an important role in the renewable energy industry, even domestic intercompany transactions can be important if they impact the amount of tax credits. For example, a development fee charged from one US entity to another could be included in the cost base for the investment tax credit. Therefore, the development fee could directly impact on the qualifying amount of investment tax credits.

Common transfer pricing issues include the calculation of development fees and the treatment of centralized engineering and management services.

Development fees
Companies involved in renewable energy development often place each development project in a separate legal entity, with a parent company or partner offering development and/or management services. Transfer pricing of these services must be addressed to potentially qualify for credits and incentives. Many renewables projects will undertake a cost segregation report in an effort to maximise their potential grant; however, a valuation will only capture the hard assets involved, while the development fee, valued by a transfer pricing study, may also qualify for a Department of Energy grant.

Transfer pricing requires that intercompany transactions be priced according to the functions and risks of each party. Since renewable energy development is inherently risky, understanding these risks is critical to properly pricing the development fee. Much like venture capital, risk decreases with each stage in the development cycle. Therefore, it is important to understand these stages and select a transfer pricing method that explicitly addresses the risk element.

Generally, renewable energy projects must go through three main stages to assess, construct, and commission a power project. These three stages make up the...
economic value chain of clean energy technology. The value related to the development varies depending on what steps within these stages have been completed.

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The operational approvals in the site assessment stage and the PPA are key milestones. The PPA determines future revenue (often for more than 10 years) and lends significant value to the operation. Once these milestones are achieved, the majority of value attributable to development has been achieved. By the time the project is in the ongoing operations phase, it typically will be earning only a routine profit margin as the major risks have been managed. Given this decline in risk as the project moves through the development cycle, the value of the development fee will increase the later in the cycle the project is transferred, as the developer would be bearing the risk for longer. Given this strong correlation between value and timing, companies should plan ahead for the impact their timing decisions will have on their transfer pricing and FIRPTA classification of assets.

The income method (a type of discounted cash flow analysis) as outlined in the US cost sharing regulations can be a useful way to value the development fee as it includes a feature for risk adjustment. An application of the income method may be used to identify the income attributable to the various income streams by using both the comparable uncontrolled transaction (CUT) method and the comparable profits method (CPM). For the CUT method, it may be possible to get data on what third parties have charged for development fees versus the total project costs. Alternatively, one may be able to apply a CPM by evaluating the routine returns expected for construction and operation for use in the income method. However, it can be difficult to find appropriate comparables due to the consolidation in the industry, with larger players purchasing startup operations to expand their renewable portfolios to meet Renewable Portfolio Standards (RPS) leaving few pure renewables players. Renewables operations are often such a small part of the larger energy conglomerates that they do not provide segmented information for their renewables operations. Therefore, comparable sets for renewables operations are often a composite of the entire industry rather than a benchmark of the specific activities undertaken, requiring adjustments to increase comparability.

Since the income method relies on projections, it is necessary to evaluate the project forecasts. The US transfer pricing regulations specify that probability weighted projections should be used, which often differ from the best case scenario projections routinely available at most companies. Therefore, it can be useful to construct a Monte Carlo simulation, computing multiple combinations of variables to determine an interquartile range of results in keeping with the Internal Revenue Service (IRS) regulations.

**Engineering and management services**

Many renewable energy companies structure their business with each entity specialising in an activity. This can lead to the provision of engineering or management services between affiliates. For services transactions, companies need to document both the benefit provided and the appropriateness of the charge. This charge can be based on cost alone, costs with a markup, or another market rate (such as hourly engineering rate). The challenge often arises in allocating the costs between affiliates. Timesheets can be helpful, but are not required. Even with timesheets, tax authorities can question the benefit received from the service. It is critical to determine which entity truly benefits from the service and provide support for that assertion.

**FIRPTA**

Foreign investment into the US can result in FIRPTA reporting and/or liability if there are US entities or US assets owned directly or indirectly by foreign investors. Foreign investors have come to understand that a disposition of a US Real Property Interest (USRPI) will be subject to US taxation. However, investors are frequently surprised by the broad reach of FIRPTA. Below we will focus on three areas where the broad reach of FIRPTA can impact foreign investment in renewable energy infrastructure assets.

**Definition of real property**

The definition of real property for purposes of FIRPTA is much broader and requires more analysis than simply determining the real estate owned by a company. The FIRPTA rules make clear that the local law definitions of real property will not be controlling. FIRPTA defines the term “real property” to include three categories of property: land and un severed natural products of the land; improvements (which include “inherently permanent struc-
tures”); and personal property associated with the use of real property.

Although the drafters of the final FIRPTA regulations derived their definition for “inherently permanent structures” from that found in Internal Revenue Code section 48 (section 48), the FIRPTA regulations are broader and specifically treat certain properties as inherently permanent even though they have not been considered to be inherently permanent under section 48. This broadened definition of inherently permanent structures increases the possibility that certain infrastructure assets, including alternative energy assets, will be considered USRPI and thus impacts the economics of a foreign person’s investment.

In addition to the broad definition of inherently permanent, each component part of the facility, as opposed to the facility as a whole, must be analysed in determining whether it is inherently permanent. While not absolute, the component-by-component analysis requires that each component part of a wind turbine, for example, be analysed. Thus, the nacelle, rotors, tower, foundation, gearbox, generator, brake, rotor shaft, and yaw drive must each be analysed to determine if such component is considered real property. The complexity of this analysis together with the broad definition of real property confirms that there is far more real property in renewable energy projects than one would assume, if one were simply relying on the standard legal definition of the term real property.

Intangibles as USRPI

The Treasury Department is considering issuing proposed regulations that would address the extent to which certain licenses, permits, franchises, or other similar rights granted by a governmental unit that are related to the value of the use or ownership of an interest in real property are USRPIs and should be taken into account in defining USRPI. Deliberations are focusing on infrastructure assets and the licenses, permits, or other similar rights that are often granted by a governmental body as a condition to operating such infrastructure.

The announcement of this potential for future proposed rulemaking has increased the awareness that certain intangibles can also be considered USRPI and are of particular relevance in renewable energy investments. For instance, a company could own significant USRPI even if it owns no land.

Consider a solar energy company that only holds leases to land. These leases or options to acquire leases themselves constitute USRPIs for purposes of FIRPTA. Further, the

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**Biography**

**Shannon Blankenship**

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Shannon Blankenship is an economist and a senior manager leading the Deloitte Denver transfer pricing group. She has 13 years of transfer pricing experience, working in both Denver and Washington, DC.

Shannon has assisted companies across all industries in the development and/or defence of their domestic and global pricing arrangements. She specialises in simplifying complex situations. Her experience crosses the breadth of transfer pricing from global documentation, headquarter cost allocation studies, intangible valuation, APAs, to planning studies. A key focus of hers has been renewable energy companies, including advising on intercompany services, intangible valuation, and development fees.

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Allison is a senior manager with the transfer pricing group in the Denver office. As part of the Deloitte Denver’s transfer pricing team, Allison assists in advising multinational companies in the restructuring of their global and regional operations, intellectual property migration strategies, and the establishment, evaluation, and monitoring of their intercompany pricing policies.

Allison’s clients have included companies operating in a wide variety of industries, including telecommunications, media and entertainment, high technology, alternative energy, and chemicals. Technical areas of experience include global documentation, intellectual property migration, and international comparability issues in connection with transfer pricing documentation.

Before joining the transfer pricing group, Allison was a director with another big four organisation’s federal tax practice, specialising in telecommunications. She has also worked for several telecommunications companies offering a variety of services such as DSL, metro ring networks, and wide area wireless networks.
direct or indirect right to share in the gross or net proceeds or profits generated by the land is itself an interest in land and should be considered USRPI. Consider a business that must obtain a conditional use permit to operate a solar array or wind turbines. Because conditional use permits (CUPs) may run with the land in accordance with state law under which they are granted and allow the grantee the right to use the land to generate electricity, the CUPs themselves may be considered USRPIs.

Other assets that may need to be analysed would include PPAs or a transmission queue position. Each would need to be analyzed before a conclusive determination could be made whether it is USRPI.

**Development stage companies**

In contrast to the broad definition of USRPI, the term “trade or business asset”, for purposes of determining if an interest in a US corporation is USRPI, is very narrowly defined and rarely includes all of the assets of a company. For example, an asset that is held for the purpose of providing for future expansion will not be considered held for the current needs of the trade or business.

The characterisation of assets as trade or business assets can be critical for foreign investors seeking to invest through a corporate “blocker” an interest in which they do not want to be USRPI. Depending on the stage of development, certain assets may be considered used for future expansion. As a result, such assets would not be considered trade or business assets for purposes of determining if an interest in a corporation is USRPI.

**Critical attention needed**

Because credits and incentives are an important part of renewable energy investment, appropriately addressing tax issues in structuring the investment may create a successful one. Critical attention should be paid to FIRPTA and transfer pricing issues when selecting the structure, the nature of investment, and the timing of a potential sale.

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**Biography**

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Christine Piar is a senior manager in the international tax services group in Washington, DC, and brings more than 13 years of international tax experience for both US-based and foreign-based multinationals, primarily in the areas of foreign tax credit planning, financing and repatriation approaches, acquisition and disposition planning, post-acquisition restructuring, and inbound investment structuring.

Christine is recognised as a firm-wide specialist on the Foreign Investment in Real Property Tax Act (FIRPTA) and is a regular speaker on the subject at both internal and external events. She has extensive experience addressing FIRPTA issues for clients in the oil and gas, energy, transportation, mining, automotive, retail, and services industries.

Christine began her career with a big five firm in Houston serving a wide range of multinational clients in the oil and gas, energy, and waste industries. Christine obtained her JD from the University of Houston School of Law and is a member of the Texas and Ohio Bars.
Footnotes

1. Treas. Reg. § 1.482 gives the Secretary the broad authority to distribute, apportion or allocate gross income, deductions, credits, and allowances to properly reflect income. Although Treas. Reg. § 1.482 is a federal tax provision, many states apply the principles of Treas. Reg. § 1.482 to challenge related-party transactions and structures at the state level. Treas. Reg. § 1.482—type provisions vary significantly among the states, but the use of arm’s-length standards or similar principles are a common theme among the state adaptations of Treas. Reg. § 1.482.

2. The eventual owners of an energy asset (such as a solar field or wind energy facility) will pay a development fee to purchase the asset from the developer. The development fee is meant to pay the developer for identifying the ideal locations, acquiring the land for the site, getting the appropriate tests and permits, and sourcing the equipment. Sometimes, the developer also engages a construction company and obtains a PPA, which could result in a higher development fee.

3. Treas. Reg. §1.482-7(g)

4. Approximately 29 states and the District of Columbia have RPS. A RPS requires electric utilities and other retail electric providers to supply a specified minimum amount of customer load with electricity from eligible renewable energy sources. Many states have credit programs in order to stimulate market and technology development so that, ultimately, renewable energy will be economically competitive with conventional forms of electric power.

5. Treas. Reg. §1.482-7(g)(2)(ix)

6. For a regulated utility, this may be impacted by commission guidelines.

7. Treas. Reg. § 1.897-1(b)(1)

8. The term “foreign person” includes a foreign corporation, foreign individual, foreign partnership, foreign trust, or foreign estate.

9. The announcement regarding this matter was contained in an advanced notice of proposed rulemaking that was published in the Federal Register on October 31, 2008.

10. Treas. Reg. § 1.897-1(f)(2) provides that an asset is used or held for use in a trade or business if it is, under the principles of Treas. Reg. § 1.864-4(c)(2), (i) held for the principal purpose of promoting the present conduct of the trade or business, (ii) acquired and held in the ordinary course of the trade or business, or (iii) otherwise held in a direct relationship to the trade or business. The section 897 regulations mirror Treas. Reg. §1.864-4(c)(2)(iv) and provide that in making a determination as to whether an asset is held in a direct relationship to the trade or business, consideration should be given as to whether the asset is needed in the trade or business to meet the present needs, as opposed to the anticipated future needs, of such trade or business.
Some things in the world are changing
Others are not

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