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March 6, 2014

FOIA Request No. 13-10-078

This is in response to your Freedom of Information Act request, received October 17, 2013, seeking digital/electronic copies of the Draft Petroleum Audit Manual and the OTA Advisor Handbook. On February 26, 2014, you agreed to narrow your request to *exclude* the OTA Advisor Handbook.

The Petroleum Audit Manual is being released to you electronically in its entirety.

No fees were incurred in processing your request.

Sincerely,

Thomas Funkhouser
Deputy Senior Director
Business Operations
International Affairs

Attachment (1)

Cambodia General Department of Taxation

PETROLEUM AUDIT MANUAL

Contents

Preface

This is a training manual for the use of staff working in petroleum auditing operations.

It is in three parts:

- A high level description of the international petroleum industry;
- A general explanation of petroleum taxes, along with guidance on particular petroleum tax issues;
- Guidance on petroleum tax administration procedures.

This guide uses the term "country" or "host country" to refer to Cambodia.

The term petroleum is used to include oil, gas and other hydrocarbons. The term petroleum tax is used to include all types of government charges levied on petroleum operations, including the government's share of profit oil under a Production Sharing Agreement (PSA).

There are a variety of types of PSAs and this guide includes reference and illustrations of some of the provisions found in PSAs from other countries as well as Cambodia. The use of the term "may" as in "A PSA may include..." is to indicate that a PSA could have the item discussed but that item may not be in the Cambodia PSA. It is included to provide a general overview of the range of provisions and how PSAs have evolved to address an issue contractually, even though that provision or approach may be absent in a particular country's PSA.

The guidance in the manual is limited to the special taxes applying to petroleum operations. It does not cover normal business taxes that may also apply to companies carrying out petroleum operations, except for withholding taxes on payments to petroleum industry subcontractors.

The manual is written in general terms. When dealing with issues affecting an individual company auditors must take account of the particular facts and circumstances of the case. The general advice in this manual is not intended to displace proper consideration of particular facts and circumstances.

This manual will be updated periodically and constructive comments and suggestions for improvements are welcome.

PART 1 THE PETROLEUM INDUSTRY

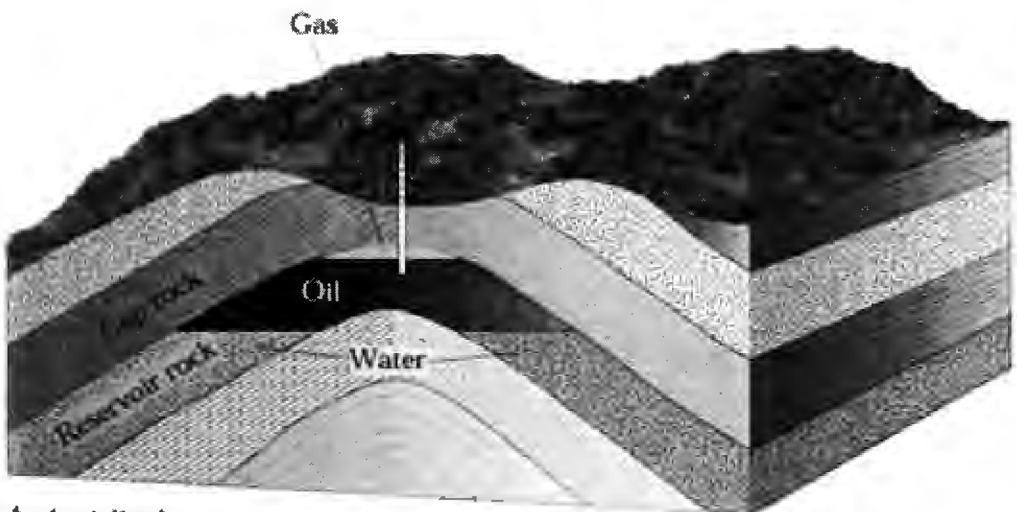
1.1 Petroleum Industry Operations

1.1.1 Introduction

Although auditors dealing with oil taxation do not need to become experts in petroleum geology and technology, a general understanding can be helpful in considering petroleum tax issues. Knowledge at the required level of detail can be obtained from the internet, through industry publications and professional education. Advantage should also be taken of any opportunities to see how the industry works in practice, for example by accepting invitations to visit petroleum installations.

1.1.2 Oil and gas formation

Oil and gas are formed (according to the most common theory) from the remains of marine and plant life, mixed with water and silt millions of years ago. Layers of rock covered the mixture as the earth's plates moved. High pressure and heat from the earth's core transformed the mixture into the complex chemicals known as hydrocarbons. These gradually rose through cracks in the rock and seeped into the atmosphere, but when rising hydrocarbons were trapped by an impervious layer of rock in the porous rock beneath, oil and gas reservoirs were created in these traps. Geologists characterize these traps in various ways, and an example of a geological section is shown below.



A. Anticlinal trap

An individual reservoir (or a group of reservoirs linked to a common geological structure) is usually described as a <u>field</u>.

1.1.3 Upstream and downstream operations

The petroleum industry is divided into <u>upstream</u> and <u>downstream</u> operations. Upstream operations are exploration for, and production and sale of, crude oil and natural gas. Downstream activities include refining of oil, liquefication of gas, distribution and sale of refined oil products, distribution and sale of gas to end users, and manufacture, distribution and sale of oil-based chemicals.

Upstream	**Downstream**
	
Exploration & Production	Refining, Distribution & Sale

Downstream activities occur in every country, and are normally subject to the same fiscal regime as other industries. Upstream activities are obviously limited to oil and gas producing countries. They are normally subject to a special fiscal regime with higher levels of taxation, since petroleum producing countries wish to secure for themselves the maximum benefit from the exploitation of their non-renewable natural resources.

The term midstream is sometimes used to describe operations at the transition from upstream to downstream – for example refining, gas liquefication, pipeline transportation. In some countries these midstream operations, while not subject to the same tax regime as petroleum production, have their own special tax regime.

1.1.4 Petroleum field life cycle

Upstream operations take place, broadly speaking, in successive stages:

This is a slightly simplified picture because:

- Appraisal may start during the exploration stage and continue into the development stage;
- There may be some development after production has started;
- Although abandonment comes after the end of production, companies provide for the cost during production.

1.1.5 Exploration

A petroleum deposit occurs in a geological structure termed a reservoir which is a pool of hydrocarbons in a porous or fractured subsurface rock formation. Exploration normally starts with a study of the available literature on the geology of the region, followed by reconnaissance geological or geophysical surveys over the region to select the areas most likely to produce petroleum. Geophysical surveys may be aeromagnetic, gravity or seismic studies. Aeromagnetic and gravity surveys attempt to detect variations in the earth's magnetic and gravitational pull caused by differences in densities of subsurface rocks. Typical seismic surveys involve use of shock waves which reflect and refract at a subsurface rock layer boundary and are analyzed to produce information about subsurface rock formations. Detailed geological and/or geophysical surveys are then carried out over the selected areas in order to choose the best locations for drilling. Sometimes in marine areas sea-bed sampling is undertaken to increase geological knowledge, and on land shallow probes may be drilled for the same purpose.

Next comes the drilling of exploration wells. During the drilling of exploration wells, as much information as possible is obtained on the geological section drilled, by taking samples of cuttings at regular intervals, cutting solid cores at selected depths, running electrical or other surveys in the hole and testing prospective intervals. If no petroleum stains are found on the cuttings at the objective formation or the surveys imply petroleum is not present in commercial quantities, the exploration hole may be plugged and abandoned. If the geological data is sufficiently promising, the exploration well may be completed as an appraisal well and/or potential producing well.

1.1.6 Appraisal

After drilling of successful exploration wells, additional test holes, normally described as appraisal wells, are drilled to determine the size and shape of the petroleum deposit and whether it is capable of commercial production. The number of appraisal wells necessary for this purpose will vary depending on the geological conditions and size of the potential reservoir. If a commercial discovery is not established, all the appraisal wells are abandoned. If a commercial discovery is established, then appraisal wells which are dry holes are abandoned, but others may be suitable for completion as producing wells.

1.1.7 Development

Once a commercial discovery is established, the next stage involves drilling of production wells and injection wells (wells where water or gas is injected to maintain or increase reservoir pressure), installation and erection of production and storage facilities, and installation of off-take facilities including pipelines, storage and pumping facilities, and tanker loading facilities.

After a commercial discovery is established there may be continuing appraisal for the purpose of planning development. Although development normally takes place before production, it is possible for further development to take place after production has started – for example the installation of new facilities to maintain oil flow.

1.1.8 Production

The next stage is production. This includes operating, maintaining and repairing the wells and facilities completed during development, and all other operations relating to production, monitoring and storage of oil and gas and transport to the designated point of delivery.

1.1.9 Abandonment

The last stage, when production has ceased, is abandonment and decommissioning of wells and other installations. This may involve plugging wells, dismantling and/or removal of installations, and cleaning and restoring the area.

1.1.10 Petroleum field stages and tax legislation terminology

The auditor should carefully review the definitions of the terms used in the PSA and the definitions used in the tax code. The terms used above to describe the life cycle of a petroleum field should be compared with the definitions used in the PSA since the PSA terms may not match the descriptions above. For example:

- The term "development operations" may be defined broadly as operations carried out in or for the purpose of producing petroleum. This is a very broad definition and may include operations described above as development but also what was described as production.

Unless care is taken these mismatches could be a source of confusion in discussions with the petroleum industry. The following are some key terms that may be used in petroleum tax legislation and PSA's whose definitions should be carefully compared.

- Exploration
- Development
- Exploration operations
- Development operations
- Production operations
- Petroleum operations
- Operating expenses
- Capital expenses
- Exploration expenses
- Development expenses

1.1.11 Petroleum wells

A petroleum well is created by drilling a hole in the earth by means of an rig turning a drill bit. Drilling fluid (known as "mud"), a complex mixture of fluids, solids and chemicals, is pumped down the inside of the drill pipe to cool the bit, lift rock cuttings to the surface, stabilize the rock and prevent subsurface formation fluids from entering the wellbore. After the hole is drilled a metal pipe, called "casing", is cemented into the hole. Usually there are several casings, with narrower casings inserted inside wider casings as the hole is extended. Hydrocarbons are gathered either through the open end of the casing or through perforations in the cement and casings.

Offshore wells are similar in principle to on-shore wells, but for obvious reasons the further they are from land and the deeper the water, the more technologically difficult (and expensive) they are to drill and operate.

There are a variety of types of rig, particularly for offshore production, including platforms, semi-submersibles, jack-ups, drill ships and floating production units.

1.1.12 Technological change and development

Major technological developments have taken place in the petroleum industry over the last half century. Developments in deep-water drilling technology have allowed extraction of petroleum at previously impossible water depths. Use of floating production facilities, deviated and horizontal drilling and remotely operated sub-sea technology has been particularly important. Other major technological developments have included 3D seismic imaging, and use of IT for more sophisticated manipulation of data. Technology for the production, transport and storage of liquid natural gas (LNG) has also developed rapidly. There have also been major changes in the design and size of tankers used for transportation of oil and gas by sea.

1.1.13 Crude oil

Oil in its natural state is described as crude oil. Crude oil from different locations varies in quality because of differences in the mix of hydrocarbons and impurities. It is classified in various ways to describe these variations, the main ones being

- location of origin;
- relative density (API gravity); and
- sulphur content.

Low density petroleum is described as light, high density as heavy, and medium density as intermediate. Low sulphur petroleum is described as sweet, high sulphur as sour. Light, sweet crudes are more valuable because they produce a higher proportion of the petroleum products most in demand, and need less refining to meet environmental standards. Location affects price because of transportation costs.

1.1.14 Natural gas

Natural gas consists mainly of methane. Gas and oil are often found together in the same reservoir, in which case the gas is described as associated gas. In many countries there is no local market for gas, for example because it cannot be sold profitably since there is no infrastructure (e.g. pipelines) for transporting the gas from its discovery area to a gas plant or facility or for delivering it to households or industrial locations. The term "stranded gas" is sometimes used to describe gas for which no market can be developed. It is difficult to transport gas for long distances, so in the past many countries with associated gas just "flared" it (i.e. burnt it off) at the wellhead, where it could not be re-injected. There is pressure to reduce flaring because of its environmental harm, and governments are in any case keen to realize the commercial potential of their gas. One way of doing so is to convert it into liquefied Natural Gas (LNG) for export. A LNG plant essentially reduces the temperature of the gas so that it becomes a much more dense liquid form, suitable for transportation in specialized containers to re-gasification plants in gas-consuming countries. (This is a simplified description of an innovative, complex and expensive technology.) With the development of this technology huge increases in international LNG production have occurred since the 1990s. Another potential commercial outlet is to build gas-fired power stations to supply electricity to the local market.

Gas found separately from oil is described as unassociated gas. This can obviously be left in the ground rather than flared, if there is no local market, though again in such cases countries may wish to monetize its value by converting it to LNG or using it for power generation.

Sometimes natural gas fields also produce low density hydrocarbons in liquid form, known as condensate, which can be refined into gasoline and other light petroleum products.

1.1.15 Measurement

Oil output is normally measured in barrels (a barrel is 42 US gallons).

Gas output is normally measured in cubic feet or meters. Gas prices are sometimes quoted by caloric value, measured in btu (British thermal units) – the typical caloric value of natural gas being roughly 1,000 BTU per cubic foot, depending on composition – or therms (one therm = 100,000 btu). Gas reserves are often measured in barrels of oil equivalent (boe), based on energy content (a boe being roughly 6000 cubic feet, or 170 cubic meters, of typical natural gas).

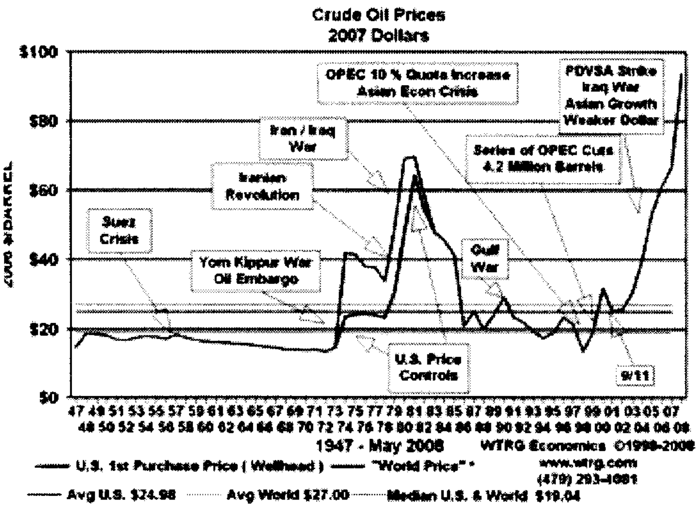
1.1.16 Prices

Oil and gas prices are normally quoted in US dollars.

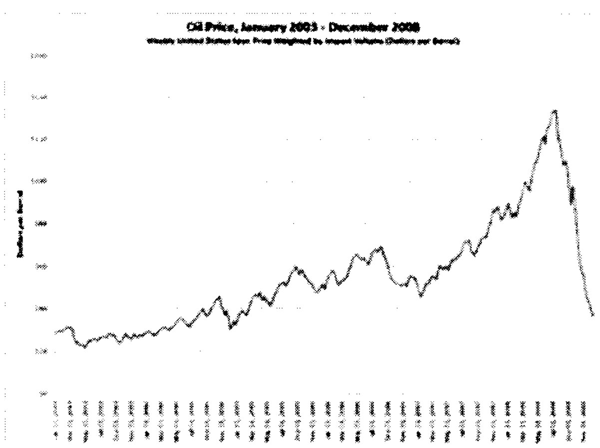
Oil

World oil prices have generally been highly volatile. The oil shocks of the 1970s, resulting from cuts in output by the Organization of Petroleum Exporting Companies (OPEC), caused oil prices to rise from around $10 a barrel to a peak of around $70. These high prices encouraged the development of major new non-OPEC oil provinces. Prices fell steadily, reaching a low of $10 a barrel in January 1999. Prices then recovered, and from 2004 there were steep increases, with oil reaching more than $140 a barrel in mid-2008. During the international financial crisis of 2008, the price then fell to less than $45 per barrel, but it has since regained some stability.

Oil prices 1947-2007



Oil prices - recent years



Gas

Gas prices tend to move broadly in step with oil prices, but the link is not always close. Gas prices are affected by the difficulty of finding a market for "stranded" gas. Where gas is sold as LNG the substantial costs of a LNG plant and of specialized transport containers and of re-gasification in the country of destination are added to the normal upfront costs of field development. Because it can easily take 20 years or more to recover these heavy upfront costs it is common for buyers and sellers of gas to enter into long term contracts either at a fixed price or with limits on the parties' ability to vary prices. Long term "take or pay" contracts are common. Under these contracts, buyers are required to make periodic payments for a fixed quantity of gas whether or not they take that quantity. The buyer is entitled to demand delivery of the product paid for in subsequent years provided certain conditions are met.

In some cases different elements of the gas supply chain (which may run from wellhead to pipeline to LNG plant to shipping container to re-gasification plant to consumer) are controlled by associated parties. In these cases the gas passes from upstream to the downstream under non-arm's length deals, for which it may be difficult to establish market prices given the absence of comparable transactions with uncontrolled prices. In some cases governments themselves may be owners or part owners of downstream facilities, and may set prices that do not reflect arm's length terms. Whether or not they own part of the supply chain they may require gas to be sold at subsidized prices to local LNG plants or power stations to provide greater incentive for the building of this infrastructure.

Such factors result in gas prices being less uniform and transparent than oil prices.

1.1.17 Benchmark crudes

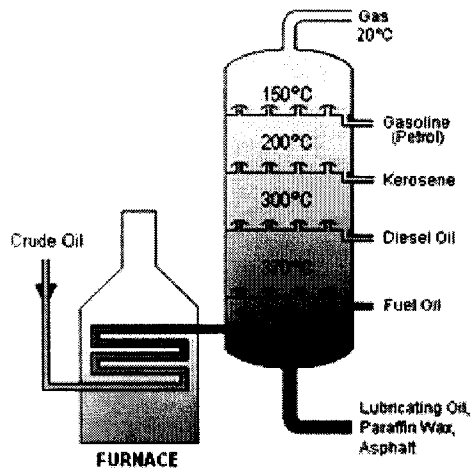
Prices for Brent and West Texas Intermediate are quoted on Commodity Exchanges, such as the New York Mercantile Exchange (NYMEX) or the Intercontinental Exchange (ICE), and the prices for these and other commonly traded crude oils (for example Dubai and OPEC Basket – a basket of weighted prices of OPEC producers) are monitored and published by publications such as Platts and Argus. These are often used as pricing benchmarks i.e. other crude oils are priced on the basis of the benchmark crude to which they are most similar, with marginal adjustments for differences in API gravity, sulphur content, and so on. (For an example of adjustments to reflect differences in API gravity, see
http://www.conocophillips.com/products/business/crude_oil/gravityscale/index.htm

For gas, quoted prices are less common and less useful. Natural gas futures are traded on NYMEX based on prices at Henry Hub (a point on the US gas pipeline system) but these may be of limited relevance to gas prices in other parts of the world, where – as explained above – gas is more difficult to trade and the price is often based on individually negotiated long-term contracts, sometimes not on arm's length terms and sometimes involving an element of subsidy.

1.1.18 Refining

Unrefined crude oil is unsuitable for most practical uses. The hydrocarbons that make up crude oil have different boiling temperatures, so oil can be refined by distillation into a range of fractions, from which (often after further processing) usable products are created. Gasoline is used for automobile fuel, kerosene for jet engine fuel and household fuel, gasoil for diesel and heating fuel, lubricating oil for engine oil, and tar or bitumen for road surfacing. Hydrocarbons are also used as the basis for a wide range of chemical products, such as plastics, lubricants, polymers, fibers, feedstock components and other products.

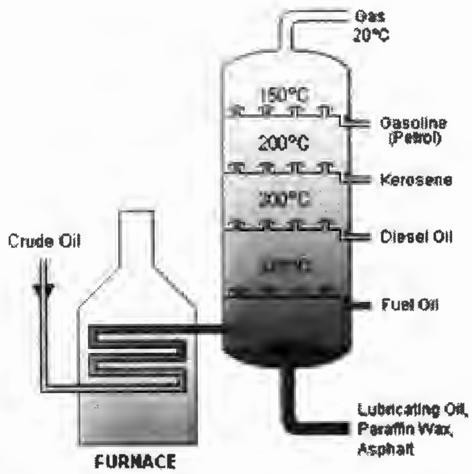
Crude oil distillation



The demand for lighter petroleum fractions, such as gasoline, is greater than for heavier fractions, so as well as distillation, refineries often subject the heavier hydrocarbon fractions to further complex chemical processes (usually described as "cracking") in order to break them down into lighter fractions.

Oil refining is a much more complex process than the above simplified description suggests – as is shown by the illustrative example of refinery processes below. More detail can be found on the internet, industry publications and other references.

Crude oil distillation



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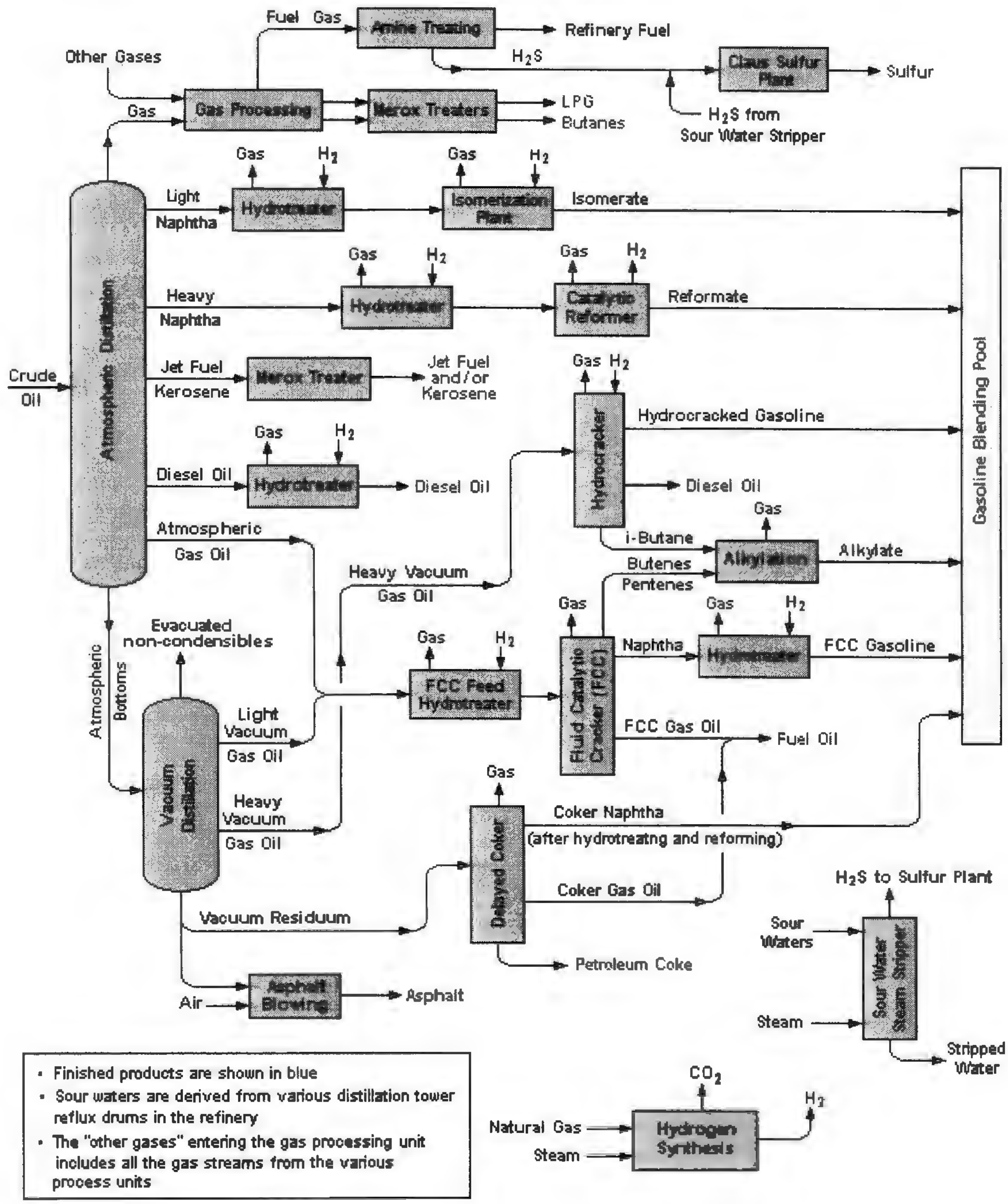


Natural gas also has to be refined to remove impurities. Again this is a complex process, though perhaps not as complex than oil refining.

1.2 Petroleum Industry Organisation

1.2.1 Introduction

Auditors dealing with petroleum taxation will be mainly concerned with participants in the petroleum industry operating in their country, but a wider knowledge of the international industry practices may be useful.

1.2.2 National oil companies

Many of the world's largest oil companies are state-controlled National Oil Companies (NOCs). Some operate as state-run commercial companies participating in petroleum operations in just the same way as other commercial equity participants; some perform a regulatory role, for example administering the production sharing rules and other provisions contained in production sharing agreements (PSAs) on the government's behalf; and some combine both roles. Many NOCs operate internationally as well as in their home state.

A somewhat critical discussion of the role of NOCs in the international oil industry can be found the IMF *Handbook on Oil, Gas and Mineral Taxation* (to be published around February 2010).

1.2.3 International oil companies

The main privately owned International Oil Companies (IOCs) are based in Europe or the US. They are often divided into "majors" and "independents", according to size. Majors include, for example, Exxon-Mobil, Royal Dutch Shell, BP, Chevron, and Total.

A petroleum licence may be issued to an international oil company and a national oil company or the country's petroleum authority entity. A petroleum operation may be carried out by joint ventures or by a single company. The PSA may allow a country's petroleum authority entity (e.g. NOC, Ministry of Petroleum, etc.) to elect to become a JV participant in any petroleum operations that reach the stage of commercial development.

1.2.4 Oil company groups

What is referred to as an IOC is normally in fact a group of companies, with a management and holding company owning shares in operating subsidiary companies. Upstream and downstream operations are normally carried out by different subsidiaries. Operations in a particular country are often carried out by a subsidiary company operating only in that country. In some countries governments allow petroleum operations to be carried out only by a separate domestically registered company. In other countries petroleum operations may be carried out by a local branch of an overseas company. An oil company operating in a country may be registered in countries with low tax rates, sometimes described as tax havens.

Some oil companies carry out only upstream or only downstream activities, but the major NOCs and IOCs usually carry out the full range of upstream and downstream activities, from exploration through to retail sale. Such companies are sometimes described as "vertically integrated".

1.2.5 Oil companies and service contractors

In recent decades oil companies have contracted out most of the actual work involved in the upstream industry to drilling contractors (e.g. Transocean, Nabors, etc.) and oil field service companies (Halliburton. Baker Hughes, Schlumberger, etc.), who work under the oil companies' supervision. Some of these are themselves very large international companies.

1.2.6 Joint ventures

Upstream petroleum projects usually require the investment of large amounts of capital. They are normally (though not always) carried out as a joint venture by several companies operating under the terms of a Joint Operating Agreement (JOA). Joint ventures allow oil companies to diversify and spread their risks, and this in turn helps them to raise the substantial finance required. (Note that although participants in a joint venture are sometimes described as partners, there is no partnership in a legal sense, since the JOA provides for the sharing of output and specified costs and not for the sharing of profits.)

The JOA provides the legal contractual framework for conduct of business under a joint venture. Its scope normally covers exploration for, and production of, petroleum, plus treatment, storage and transportation. It also sets out the accounting and auditing arrangements. One of the participators is designated as operator under the terms of the agreement. The operator normally holds the greatest, or one of the greatest, percentage interests in the joint venture. The operator is normally a well-established oil company with substantial experience and substantial financial and technical resources. The operator is responsible for carrying out the operations of the joint venture in a proper manner in accordance with the terms of the agreement, and in practice normally takes the initiative in making proposals. Operators generally act as agents for the other joint venture parties and the basis of their remuneration is set out in the JOA. This is usually stated to be on a non-profit basis. The joint venture partners are required to contribute their share of joint venture costs as notified by the operator ("cash calls"). Occasionally a partner's interest is "carried": this means that the other partner(s) pay that partner's costs, which are subsequently reimbursed, from that partner's share of petroleum. This often happens where one of the original parties has "farmed out" part of their interest to another party.

1.2.7 International oil companies

A petroleum licence may be issued to an international oil company and a national oil company or petroleum authority entity of that country. A petroleum operation may be carried out by joint ventures or by a single company. The PSA may allow a country's petroleum authority entity (e.g. NOC) to elect to become a JV participant in any petroleum operations that reach the stage of commercial development.

1.3 Petroleum Industry Accounting

1.3.1 Introduction

International oil companies prepare accounts in accordance with commercial generally accepted accounting principles (GAAP). In addition to GAAP there are some specific recommended practices for oil industry accounting. A useful summary of relevant US and international accounting standards can be found at http://www.hmrc.gov.uk/manuals/otmanual/OT02000.htm.

To some extent, accounting principles are overridden for tax purposes by specific rules in PSAs and tax legislation. For example, the accounting literature discusses alternative methods of accounting for exploration costs (briefly explained below), but this is of limited relevance for tax purposes since their tax treatment is generally spelt out clearly in PSAs and tax legislation. Nevertheless it is helpful to have a broad understanding of the commercial accounting principles that apply to oil operations because:

- They may be relevant where there are no specific tax rules, and
- Companies should reconcile their commercial and their taxable profits. An understanding of commercial accounting principles will make this reconciliation easier to follow.

1.3.2 Commercial accounting principles

It is beyond the scope of this manual to consider fully all of the general principles of commercial accounting. In general :

- Under the accruals principle, income and expenditure are allocated in the period to which they relate, which may be different from the period when payment is actually made or received. Most country's PSAs and tax legislation require oil companies to account on the accruals basis.
- Expenditures which create an enduring benefit is capitalized, and not treated as an expenditure which is expensed entirely in the year when it was incurred. (The terms "capex" – capital expenditure – and "opex" – operating expenditure – are commonly used in the petroleum industry.)
- Profits are adjusted for stocks of petroleum produced but not yet delivered, or materials purchased for consumption but not used during the year.

1.3.3 Accounting methods for petroleum costs

There are two different methods of accounting commonly used to track and account for petroleum costs for financial accounting purposes:

- Under the "successful efforts" method, exploration costs are capitalized only if they specifically relate to a successful operation – otherwise they are written off immediately.
- Under the "full costs" method, all costs within a common "cost pool" are capitalized. So for example a license area (or even an entire petroleum province) might be treated as a cost pool, and an exploration well within that area capitalized even if unsuccessful, so long as exploration was on-going in the area concerned.

Additionally, the treatment of a cost can vary depending on whether it is for tax purposes or financial reporting purposes. Below are two tables illustrating the differences in how costs might be treated for Financial (Successful efforts/full cost) and for Tax purposes.

Expense Type	**Financial Reporting Successful Efforts (SE)**	**Financial Reporting Full Cost (FC)**

Acquisition (e.g. bonus)	Capitalize	Capitalize
Geological & Geophysical	Capitalize or expense	Capitalize
Exploration - Dry Hole	Expense	Capitalize
Exploration–Success	Capitalize	Capitalize
Development–Dry Hole	Capitalize	Capitalize
Development – Success	Capitalize	Capitalize

Expense Type	**Tax Reporting**	**Financial Reporting**
Dry hole wells:		
Exploratory	Expense	Expense
Development	Expense	Capitalize
Successful wells:		
Intangible costs	Expense	Capitalize
Tangible costs	Capitalize	Capitalize
Acquisition (e.g. bonus)	Capitalize	Capitalize
Geological & Geophysical	Capitalize or expense	Capitalize or expense

1.3.4 Accounting for oil and gas reserves

Another important but difficult accounting issue is the treatment of oil and gas reserves. An oil company's underlying (i.e. un-extracted), oil and gas reserves may form its most valuable economic asset. These are not recorded in the company's balance sheets, but have to be disclosed in a prescribed format in countries which regulate companies which are publicly traded. In the UK, oil and gas reserves disclosures are reported in quantitative terms while in the USA they are reported at a standardized measure of discounted future US$ cash flows pursuant to the methodology required by the U.S. Securities and Exchange Commission (SEC). These reserve quantities cannot be measured exactly since their estimation involves some subjective judgment based on limited data concerning the geological subsurface. In addition, oil companies' ability to claim ownership of oil and gas reserves may depend on the precise legal terms under which they operate in particular countries.

Oil and gas reserves are generally categorized as proved, probable and possible. Depletion calculations typically utilize proved or proved plus probable reserves. The reserves used for tax purposes will depend on what is allowed by legislation. If not addressed in a country's legislation, the reserves applicable for tax purposes may be based on the reserves accepted by the petroleum authority. The quantification of oil and gas reserves may be of some relevance as a taxation issue for depletion deductions or if the tax code uses them to affect the rate of tax depreciation of a limited class of assets (e.g. transport facilities) on which capital allowances are given on a unit of production basis.

1.3.5 Underliftings and overliftings

Another petroleum accounting issue with relevance to tax is the treatment of "underliftings" and "overliftings". Lifting refers to the share of production each party is entitled to during a given accounting period and imbalances between the parties can occur. Where petroleum operations are carried out by a joint venture, it is sometimes impractical for the individual partners to share each lifting of petroleum exactly in accordance with their percentage equity interests, so at the accounting date one partner may have lifted slightly more petroleum than it is entitled to and another slightly less. Adjustments will be made for this on future liftings, but in the meantime these under- and overliftings have to be accounted for. Recommended practice appears to be gravitating towards accounting on the basis of entitlement, not actual liftings, with the adjustments required being valued at market value rather than cost. If a country's tax code requires an oil company to account on the accrual basis, their accounts should reflect liftings to which they are entitled rather than actual liftings. From a tax point of view the overriding principle is that all petroleum produced should be valued at market price as determined by the PSAs. It is important that different JV partners should account on a consistent basis, and that that adjustments for over- and underliftings should not result in some petroleum produced being valued at less than market price (which would happen, for example, if Company A excluded the market value of overlifted petroleum but company B accounted for underlifted petroleum at cost rather than market value).

1.3.6 Computer-based accounting systems

International oil companies generally use sophisticated computer-based systems (e.g. SAP) to produce their accounting records. Transactions are input to the system using codes, on the basis of which the item concerned will be properly allocated in the accounts – but only if the code used is correct. Clearly, an understanding and testing of the computer-based system used is essential for the purpose of auditing the company concerned. An auditor should request a copy of the "Chart of Accounts" in order to understand how the accounting records are organized. The auditor should also request the company to provide a general overview of their accounting system, its reporting capability and any differences between financial and tax reporting of expenditures.

1.3.7 JOA and PSA controls

The detailed accounting procedures set out in JOAs are part of a wider system of joint venture controls. PSAs were originally modeled on JOAs, and incorporate similar accounting procedures and controls. Where a PSA is between the government or NOC and a group of contractor companies operating under a joint venture, both a JOA and a PSA will be in place. Broadly speaking, the PSA governs the relations between the government/NOC and the contractor companies, whereas the JOA governs the relations of contractor companies to each other. Invariably there is considerable overlap between their provisions, and the JOA can be seen as reinforcing many of the PSA controls.

Typically, under the terms of JOAs and PSAs, the operator operates under the supervision and control of an Operating Committee. The agreement ensures that the Committee is kept sufficiently informed to exercise this function. The agreements will specify when, how often or what operations require regular meetings of the Committee to take place. These are structured meetings with a pre-set agenda, and circulation of minutes. Although much business is discussed on an informal and consensual basis, formal voting procedures are laid down for reaching decisions. In the Committee established by the JOA, normally all the participators are represented, and their votes are weighted according to their percentage interest in the venture. The Committee established by a PSA is normally composed half of representatives appointed by the contractor companies, and half of representatives appointed by the government/NOC, one of whom is chairman. In some countries, the Chairman may have the casting vote in the event of disagreement, while in others disagreement resolution must be unanimous, with unresolved disagreements referred for binding arbitration.

Under the PSA, the operator may not be allowed to carry out an operation under these agreements unless and until a work program and budget have been approved by the Committee. The main exception to this is where action has to be taken in an emergency. Normally there are separate provisions for approval of programs and budgets for the different stages of exploration, development and production. Approval of a program authorizes and obliges the operator to proceed in accordance with it, subject to further controls mentioned below. Generally the budget will be analyzed by major projects, with appropriate further detail on each project.

Agreements normally provide that, for at least certain categories of expenditure, the operator must apply to the Operating Committee for an Authorization for Expenditure (AFE) before expenditure is incurred. The AFE must relate to a previously approved budget. To reduce transactions, a range of costs may be covered by the same AFE. The agreement normally provides that expenditure is deemed to be approved unless an objection is made within a certain time. This prevents expenditure from being delayed simply because of a failure to provide approval. Most JOA's require advance approval of contracts over a stated minimum threshold, and this is also often required by PSAs.

There may be specific requirements for AFEs or pre-approval of contracts above defined limits within the PSA itself or an attached accounting and reporting procedure.

1.3.8 Audit of oil companies

International oil companies are subject to various kinds of audit, in addition to the tax audit. These include:

- External audit by the company's auditors, preparatory to the publication of approved financial accounts
- Internal audit
- Joint interest audit (sometimes called joint venture audits)

Companies are also subject to audit under the terms of the PSA – generally known as the cost recovery audit. In some countries this is separate from the tax audit, but there is inevitably a major overlap between them, which can create fundamental uncertainty as to whether the tax auditors or the auditors appointed under the terms of the PSA have final responsibility for determining the figures to be used in tax computations.

A problem can arise if the PSA restricts or allows only one single government audit of the PSA accounting records and the Income Tax Act contains statutory powers of audit. Since tax examination audits and cost recovery type audits have a different focus or objective, the issue concerns which government group will be responsible for conducting the audits. A common problem is when the petroleum law covering the PSA conflicts with the law on taxation. Some common areas of conflict include:

- Tax rate in PSA is different than what is stated in the law on taxation

- Depreciation methods allowed
- Whether VAT can be applied to any production used by operator for surface facilities
- Which agency (tax authority or petroleum authority) can perform audits
- Treatment of expenditures (expense or capitalize)

1.3.9 External audit

The external audit normally consists of a combination of compliance tests (tests of controls and systems) and substantive tests (tests of actual transactions). The external auditor may produce a detailed report and recommendations for the company, but normally the only published outcome is an audit report attached to the company's accounts. This normally consists of a general statement as to whether the accounts present a fair view and are properly prepared in accordance with the records. The view in the report is based on a combination of fact, tests and judgment. In reaching this view the auditors will generally disregard matters not considered material. The external audit does not cover the company's tax returns, or the adjustments to the commercial profits necessary to calculate taxable profits. For these reasons an external audit report can by no means be regarded as conclusive for tax purposes. The external audit is, however, an important financial control, and an important test of the reliability of a company's accounts.

1.3.10 Internal audit

An internal audit is normally carried out by an independent department within the company's organization. Often it is carried out by a specialist team from the company's head office in its home country. The scope of internal audit activity in any year may not be comprehensive. Its emphasis is usually on making sure that controls are working properly. For example, ensuring that those responsible for expenditure have appropriate authority and that they do not exceed the level of their authority; or ensuring that contractors working for the company do not obtain access to confidential information. Typically, the internal audit work will be preceded by an audit plan and will result in an audit report.

1.3.11 Joint interest audit

Companies acting as operators are subject to audits by their joint interest partners. The JOA grants non-operators the right to appoint an audit team. Normally this is a joint audit team acting on behalf of all the non-operators. The team is frequently drawn from their accounting or internal audit staff, but may include representatives from external auditors. Normally audit rights extend for a period of two years. The main purpose of the joint interest audit is to ensure that the operator has acted in accordance with the terms of the JOA that are intended to protect the interests of the joint venture parties. The concept of materiality is less important than in the case of the external audit. Normally the audit will focus on the areas of more specific interest to the parties: for example whether charges made for the operator's overhead costs are justified; whether the cash generated by cash calls has been properly managed; whether purchasing and contracting procedures have been economical and efficient or whether Joint Interest Billing (JIB) statements were correct.

The joint operating agreement (JOA) contains provisions that address joint interest audits and the accounting procedures which the venture participants have agreed to follow for record keeping and tracking expenses. The interest holder who has been selected by the co-venturers to be the operator will conduct operations for the benefit of all parties. Such operations include, but are not limited to, arranging for the drilling of the wells, purchasing supplies and equipment, filing regulatory forms and permit applications, etc. An operator will estimate the cash that will be required to pay invoices and meet the obligations for a projected period (e.g. 1-4 months) of time. The operator may request a cash advance or pre-payment of these estimated costs by the non-operator joint interest holders. These pre-payments are referred to as "cash calls" and used by the operator to pay for estimated expenses. Alternatively, the operator could pay the total costs of the actual expenses as they occur and then periodically bill the joint interest owners for their proportionate part. Under either method the operator will typically submit a billing statement to the non-operator joint interest owners in a well or block for the joint interest holders allocation of the costs incurred by the operator. These statements are referred to as Joint Interest Billing (JIB) statements and show the amount owed by the joint interest holder and any credits or debits from past overpayments or underpayments. These billing statements typically are a summary statement of the activities and expenditures conducted by the operator for all the parties who own an interest in the well or license. The joint interest billing statement is essentially a bill to the joint interest parties for their proportionate part of the expenditures made by the operator for the benefit of all parties. These summary statements generally do not contain sufficient detail for a non-operator joint interest owner to assess the accuracy of the individual expenses associated with a given activity. A joint interest audit is primarily a compliance and verification review of costs and revenues. The audit objective is to verify and validate the itemized details that make up the charges made to the joint account by the operator.

Below is a simplified example where three oil companies own an interest in an oil and gas license (e.g. concession, PSA). The respective interests owned by the three oil companies in the license is shown under the allocation and they have selected Oil company A to be the operator and perform various duties on behalf of the parties (e.g. arrange for and supervise the drilling of a well, purchase supplies, file regulatory permits, etc.). Oil Company A arranged for the drilling of a well and would submit a Joint Interest Billing statement to the respective parties for their proportionate part of expenses as follows:

Expense	**Amount**
Drilling Well No. 1 (Currently in progress) (IDC)	$ 500,000.00
Drilling Well No. 1 (Equipment)	$ 200,000.00
Fuel and power	$ 50,000.00
Direct personnel salaries	$ 300,000.00
Total direct expenses	$ 1,050,000.00
Indirect Charge (JOA allowance 5%)	$ 52,500.00
Total Charges	$ 1,102,500.00
Allocation	
Oil Company A (operator) - 50% joint interest	$ 551,250.00
Oil Company B (non-operator) - 30% joint interest	$ 330,750.00
Oil Company C (non-operator)- 20% joint interest	$ 220,500.00
	$ 1,102,500.00

Below are examples of the types of review and examination that would typically be performed in a joint interest type audit conducted by a petroleum authority or national oil company who was a joint interest holder in the oil and gas license. These same types of questions may be applicable in a tax examination audit.

Work Programs

- Was the work program submitted to the operating committee or management committee pursuant to the production sharing agreement (PSA) or joint operating agreement (JOA) provisions?
- Were the work program budgets required to be revised when there is a change in the activities planned under the work program?
- Did the budget process and activities under a work program comply with any approval procedures under the PSA or JOA?
- Were statements of expenditures required to be prepared under the PSA or JOA and furnished to the joint interest parties?
- Were notices timely submitted to joint interest parties to participate in activities and whether responses were timely submitted electing to participate or declining to participate in an operation?
- Non-consent provisions in a JOA may give rise to a carried interest arrangement. Were any non-consent operations conducted and was the notification requirements, election process and response times specified under the JOA complied with?
- Non-consent operations typically allow the consenting parties to recoup and recover some multiple (e.g. 500%) of all costs to drill, complete and equip the well. When did payout or recoupment of those costs occur and were production revenues properly allocated before and after payout?

Authority for Expenditures

Joint Operating Agreements have provisions for conducting or proposing operations and seeking approval from joint interest parties to participate in the operation. Authority for Expenditure (AFE) are submitted to a joint interest party which outlines the proposed operation and an estimate of its cost breakdown.

- Were the AFE's prepared for all required operations and submitted pursuant to the provisions of the JOA?
- Were joint interest party's elections or approvals made before the operation commenced?
- Were supplemental or revised AFE's prepared when an operation was anticipated to be over spent or costs exceeded the original AFE by a percentage amount specified in the JOA?

Cash Call

The operator estimates the amount of money they will need each month in order to conduct operations. A "Cash Call" is a pre-payment amount paid by the non-operators to the operators to cover the estimated expenses to conduct operations. Since the payment is based on estimated charges, periodically the operator reconciles the amounts paid by the non-operators for any over-payments or under payments. The reconciliation results in credits for any over-payment made by non-operators or additional amounts owed if deficient.

- Were cash calls made timely and pursuant to the provisions in the JOA
- Were cash calls made pursuant to any approval process for work programs
- Did the cash call statements contain the required information required by the JOA
- Were any special cash advances needed for unforeseen activities and whether the joint interest parties were given adequate notice or information needed to secure internal approval to provide the funds
- Were cash calls or special advances received within the time specified in the JOA
- Were cash calls approved at the appropriate level

Joint Interest Billing Statements

The operator often pays for all the costs of the operations conducted on a property and then bills the non-operators for their proportionate share of the costs. The operator will bill non-opertosr for their portion of costs incurred through a joint interest billing statement. Alternatively the operator will use cash advances (e.g. cash calls) paid by non-operators for the estimated share of the expenses. An audit may examine the following:

- Were Joint Interest Billing (JIB) statements submitted pursuant to the JOA requirements
- Were the JIB statements accurate and complete?
- Do the JIB reconcile with the trial balances?
- Were any cash reconciliation statements prepared along with the JIB and were they accurate and complete?
- Were the JIB's approved at the appropriate level?

Accounts Payable

- Sample source documents for goods received, services, purchase orders and other significant items
- Were purchase orders approved at the appropriate level?
- Review invoices from consultants and verify day rate, nature of the consultants activity and the exploration or production area, block or project they worked on?
- Does the general ledger agree with the details of the area, block or project?
- Review vendor balances and verify their accuracy?
- Were any disputed amounts owed by or to a vendor properly reconciled?

Production Sharing Agreement (PSA) Cost Recovery

An examination or audit of a PSA often focuses on cost recovery provisions to determine whether expenditures were treated correctly (e.g. capitalized or expensed) under the provisions of the PSA.

- Review the itemized list of expenditures subject to cost recovery and determine whether the expenditures subject to cost recovery were correct in amount and character (e.g. tangible, intangible, exploration, development, capitalized, etc.)
- Review the depreciation schedule for the tangible assets subject to the license or production area and determine whether the depreciation deductions were correct
- Were the expenditures made or placed in service in the accounting period where they were deducted from production revenues or profit oil split?
- Review the list of intangible drilling costs for selected wells and verify their accuracy and validity. Were the intangible drilling costs correct?

1.3.12 Approval procedures and audit

Where a JOA or PSA contains detailed procedures for particular costs or contracts to be approved, Joint Venture (JV) or government auditors may focus on whether those procedures have been correctly followed. If not, JV auditors could in theory demand repayment of cash calls, and government auditors could refuse to accept the cost as recoverable. A PSA may contain few if any specific requirements for costs and contracts to be approved, so the tests for recoverability are generally based on substance rather than procedure.

1.3.13 Depreciation, Depletion and Amortization

Depreciation and Depletion represent the decline in value of a tangible asset (e.g. equipment) due to wear, use or the extraction of a natural resource. Amortization is a method of recovering the costs of intangible assets (e.g. patents). Cost centers are used in petroleum accounting and define how capitalized costs are accumulated for purposes of Depreciation, Depletion and Amortization (DD&A). Cost centers are generally set up in the accounting records to track the property and depreciable assets associated with a field, reservoir or contract area. The contract area covered by a production sharing agreement is often referred to as a "Block" (e.g. PSA covering Block "A"). Cost centers are a convenient way of tracking costs, allocating them by function or classification, apportioning them to wells or properties, and making the appropriate financial or tax treatment for an asset. DD&A are "non-cash" deductions because they do not represent the actual payment of cash. Some common methods to calculate depreciation are the Straightline Method, Declining balance Method and Unit of Production Method. Below are some examples for each of these methods.

Straight Line Method assumes a constant depreciation value per year

Annual Depreciation $= \underline{(P - S)} / N$

Where P is the price of the asset; N is the assets useful life and S is the residual or salvage value of the asset.

Example calculation:

A pump which costs $20,000 is installed at an oil well in 2007. The pump is expected to last 5 years and have a salvage value of $5,000 at the end of its useful life.

Annual depreciation = ($20,000 - $5,000) / 5 = $3,000/Year

Year	Beginning Book Value	Depreciation	Ending Book value
2007	$20,000	($3000)	$17,000
2008	$17,000	($3000)	$14,000
2009	$14,000	($3000)	$11,000
2010	$11,000	($3000)	$8000
2011	$8000	($3000)	$5000

The declining balance method assumes a constant amortization rate per year. It is an accelerated depreciation method which uses the straight-line rate multiplied by a declining balance factor (100%, 150%, 200%). The computation ignores the residual or salvage value of the asset. However, the asset is not depreciated below the residual value. The asset is amortized by a yearly depreciation factor determined by: (Decline %) / N

Example

C (Asset Price) = $20,000

N (Class Life Period) = 5 Years

Declining balance % = 100%

Depreciation factor = (100 %) / 5years = 20% Per Year

1st Year Depreciation = (20%) ($20,000) = $4,000

2nd Year Depreciation = (20%) ($20,000 - $4,000) = $3,200

In the above example the declining balance percentage was 100%. The declining balance method is referred to as the Double Declining Balance when the declining balance percentage is 200%. Note that the declining balance method allows for a greater depreciation deduction in early years and less of a deduction in later years. This method, when allowed under a tax code, provides the taxpayer a means to recoup their investment at a faster rate for tax purposes.

The unit of production method of depreciation relates depreciation to the wear and tear of the asset as it is used to produce. The depreciation expense for a given year is based on the number of units produced during that year. The units used to measure the useful life can be any measurement (e.g. meters drilled, items produced, machine hours, tons mined, barrels oil produced, etc.) that is associated with the function of the asset. Annual depreciation for a given year is based on the number of units produced during that year calculated as (depreciation rate per unit)(units produced in current year). The Depreciation rate per unit is calculated as (Cost – Salvage value) / (Total lifetime units produced). The method does not depreciate the asset below its expected residual value.

Example

A Drilling rig is purchased for $1,300,000. The Rig is estimated to be able to drill a total of 10,000,000 meters. The Salvage value of the rig after drilling 10,000,000 meters is expected to be $150,000. In the first year the rig drills 155,000 meters and in the second year the rig drills 100,000 meters.

Cost = $1,300,000

Salvage value = $150,000

Total useful life = 10,000,000 meters drilled

Depreciation Factor = ($1,300,000 – $150,000) / (10,000,000 meters) = $0.115/meter

1st Year Depreciation = (155,000 meters drilled) (0.115) = $17,825

2nd Year Depreciation = (100,000 meters drilled) (0.115) = $11,500

Depletion

Depletion is associated with the actual extracting of a natural resource (e.g. oil, minerals, timber, etc.) and represents the financial cost associated with the decline in value of the original resource due to the physical depletion (e.g. withdrawal of oil and gas from the reservoir) of the resource.

Depletion formula:
(Adjusted Basis) (Units removed and sold during year) / (Units Recoverable at beginning of year)
Where adjusted basis is: (cost basis) – (cumulative depletion taken)

Example Calculation for Depletion
An oil property has a cumulative investment (cost basis) of $150,000. The oil reserves which are recoverable are 1,000,000 barrels (bbl) and the annual production extracted and sold is 50,000 bbl each year.

Year 1 cost depletion: ($150,000) [(50,000) / (1,000,000)] = $7,500
Year 2 cost depletion: ($150,000 - $7,500) [(50,000)/(1,000,000 - 50,000)] = $7500

1.3.14 Petroleum Business Expenses

There are a number of expenditures associated with oil and gas exploration and production operations. These expenses are broken down into general categories of tangible and intangible costs to track the expenses. Modern tax audits generally examine whether the business ***expenditure*** is ordinary, necessary, reasonable and incurred in a profit-motivated activity. Such expenses would include interest paid on loans, withholding taxes paid, royalty payments to the host country, special remuneratory taxes paid to the host government, capital expenditure allowances (depreciation), net losses from past years which are carried forward, bad debts, charitable donation allowances and others. Typical petroleum business expenses include exploration costs (e.g. seismic) well drilling costs (e.g IDC), operating expenses for a producing well, capital expenses for production facilities, repairs and maintenance of a well or production equipment, oil and gas license acquisitions and divestitures. Examples of general business expense breakdown on the support exhibits to the tax form for an oil company include:
Legal and professional expenses
Technical services expenses
Intangible Drilling Costs (IDC)
Research and development expenses
Worthless stock deductions
Material and supply expenses
Cost of goods sold
Repairs and maintenance expenses
Depreciation and amortization
Depletion (may not be allowed for tax purposes in some countries)
Like kind exchanges
Acquisitions and divestitures
Capital gains and losses
Environmental expenses
Acquisitions and divestitures

Operating expenses

Intangible and Tangible Drilling Costs. Intangible costs in petroleum operations refers to any cost incurred in petroleum operations which in itself has no salvage value and which is incidental to and necessary for the drilling of wells and preparation of wells for the production of petroleum. Such costs are generally referred as intangible drilling costs. Tangible drilling costs involve expenses for material and equipment which have a salvage value and are an asset associated with the well. These tangible assets are generally used for production operations or well control and have an economic life span. An Authority For Expenditure (AFE) is a document used by oil companies to outline the estimated expenditures expected to be incurred for drilling a well, purchasing a piece of equipment or conducting some operation associated with exploration, development or production activities. The AFE is an estmate and the actual costs may be different, however it is a useful document to review when conducting an audit since it outlines the tangible and intangible expenditure planned for a given operation.

Typical examples of Intangible Drilling Costs (IDC) include:
Site costs (e.g. bull dozing, surveys, road building, etc.)
Rig transport (e.g. mobilization and demobilization)
Rig operations (e.g. labor, etc.)
Labor, fuel and power
Drill bits
Drilling fluid (mud) and chemicals
Formation evaluation (e.g. logs, DST)
Cementing services (e.g. casing)
Wireline services
Completion tools and perforating
Well stimulation (e.g. formation acidizing or fracturing)
Well supplies
Waste disposal and restoration

Typical examples of Tangible Drilling Costs include:
Site costs (e.g. bull dozing, surveys, road building, etc.)
Casing (e.g. surface, intermediate, production, tubing)
Float collar equipment, casing guide shoes, centralizers
Well head equipt. (e.g. valve manifold)
Storage tanks
Separators, Heater Treaters
Artificial lift equipment (e.g. pumps)
Rods
Tank battery
Gathering lines, line pipe, valves, fittings
Cranes
Compressors
Lease Automatic Custody Transfer (LACT) unit
Meters

Dehydration equipment

Operating Expenses. The costs to operate and maintain property and equipment on a petroleum license are referred to as Lease/License Operating Expenses (LOE). The term "Lease", in this context, may be encountered in accounting documentation and refers to the petroleum license or contract that gives the company the right to search for and extract oil and gas. The term is sometimes used in an accounting chart of accounts (e.g. Lease Operating Expenses) and is used to track the operating expenses associated with the equipment on a petroleum license or a well, field or area covered by the petroleum license. Typical examples of Lease/License Operating Expenses include:
Power & Fuel to operate surface production facilities
Contract pumping services
Salt Water Disposal
Well servicing (paraffin removal, down-hole stimulation, flow optimization, well testing)
Chemicals & treating of the well
Equipment rental
Contract labor
Repairs to surface equipment
Repairs to sub-surface equipment
Materials & supplies
Administrative Overhead

Geological and Geophysical Costs. Geological and geophysical (G&G) expenditures involve surveys, technical data, studies, and salaries for scouts, geologists, engineers and geophysical crews. The surveys and data are used to locate commercial quantities of oil and gas deposits. Geological and geophysical data can be collected by lowering special tools down into the well bore and measuring the subsurface rock properties of a formation. Examples of geological data include caliper logs, lithology logs, resistivity logs and porosity logs. Geophysical data typically involves the use of seismic techniques. Seismic covers a larger area using techniques that involves acoustic measurements of a formation. Typically, a surface energy source generates sound waves that travel down through the rock layers and provides information about the general shape of subsurface formations. It uses principles of acoustic impedence and reflection. When sound waves travel through rock layters, portions of the energy are reflected at interface points between two materials with different acoustic impedence. The reflected energy is measured at the surface using geophones on land or hydrophones in water. 2D and 3D seismic surveys are often used to identify areas with geological features which are favorable for hydrocarbon deposits. 2D seismic provides a two-dimensional picture of the subsurface while 3D provides a three dimensional picture. 2D is cheaper to perform while 3D is more expensive. Other types of geophysical measurements are gravimetric surveys which are used to identify vertical and horizontal variations in the density of subsurface rock. Some seismic surveys may be associated with locating the optimal drill site and may be categorized as an intangible drilling cost associated with a specific well. The tax issue for G&G data expenditures is:

- whether they are ordinary and necessary business expenses and allowed to be expensed in the period incurred, or

- whether they are capital expenditures which should be amortized over their useful life or the life of a particular property and what is the useful life of such data

The auditor will have to look to their tax code to make a determination on how such costs should be treated. Some guidance on how best to treat such expenses may be found in the PSA or in how the petroleum authority treats such expenses under the PSA. Some examples of the G&G technical data used in exploration and development activities include:
Gravimetric Surveys
Magnetic Surveys
Seismic Surveys (2D, 3D)
Geological and engineering studies
Cores
Paleontological Studies
Geochemical Studies
Well logs (e.g. resistivity, gama ray, density, neutron)
Drill Stem Tests

Environmental ***Expenses. These*** costs may or may not qualify as current expense deductions. The tax issue is whether the expenditure is in the nature of a fine or penalty; whether it is in the nature of a business expense or whether it is in the nature of a capital expense, The tax treatment of environmental fines and penalties depends on the facts and circumstances surrounding the nature of the assessment. A fine incurred in carrying on a business is deductible if the payment is exacted for compensatory or remedial purposes. If the fine is a penalty or serves a deterrent and retributive function (similar to a criminal fine), then it is generally not deductible as an ordinary and necessary business expense. Environmental remediation costs incurred to adapt a property to a new or different use is generally considered to be a capital expenditure. Examples of general expenditure categories that may have an environmentally related charge include:
Consulting Fees
Professional Fees
Legal expense
Penalties and Fines
Settlement Payments
Permit Costs
Repair and Maintenance Expenses
Cleanup, Removal and Disposal Costs
Site Remediation
Project Abandonment Costs

1.3.15 Net Operating Loss Carry-forwards

Whenever a taxpayer has a 'tax loss' their taxable income for that period is generally deemed to be zero. Often, that loss can be carried forward to offset income in future years. The net operating loss of the business for any taxable year immediately preceding the current taxable year, which had not been previously offset as a deduction from gross income, may be allowed under the tax code to be carried over as a deduction from gross income for some period of time (e.g. 5 years) to future taxable years immediately following the year of the loss. Such loss carry-forwards may be limited or not allowed if the net loss was incurred in a taxable year during which the taxpayer was exempt from income tax.

Additionally, a country's tax code may restrict the loss carry-forward allowance if there was a substantial change in the ownership of the business or if there is a substantial change in the primary business the enterprise is engaged in. While the general practice is that losses can be carried forward, their utilization by companies may be subject to a "continuity of ownership" test or a "same business" test under a country's tax code. The continuity of ownership test limits the extent to which the benefit of applying a loss can accrue to individuals who did not incur the loss. The same business test may relax or eliminate the continuity of ownership test where a business conducts essentially the same business activity in the year the loss is incurred and claimed.

Another consideration the auditor will need to consider is whether there are any restrictions in the country's tax law on how the loss is used. Certain losses may essentially be quarantined from other types of losses and may not be deductible from all of a taxpayer's taxable income. A country's tax code could specify that losses can be carried forward and offset only against gains from the same type of income in a later income year.

Restrictions that **may** apply to the utilization of losses in certain circumstances, depending on the tax code, include:

- Capital losses may only be offset against capital gains.
- Passive losses may only be offset against passive gains

The auditor will need to examine the country's tax code and other legal precedent to determine whether any restrictions apply. Note that oil and gas activity is not a passive activity and ownership of a working interest is considered an active activity engaged in oil and gas exploration, exploitation and development. Note that income and losses to limited partners in a partnership may constitute passive income or losses and may be subject to any restrictions that apply. Generally, this is because a limited partner is considered a "passive" participant and not involved in the active management of the partnership.

1.4 Petroleum Industry Regulation and Legal Principles

1.4.1 Petroleum Legal Principles Generally Used

Every state has sovereignty over its mineral resources under international law. International law also has rules governing rights to minerals in or under the sea, though these are sometimes a source of dispute.

Where petroleum fields (or other mineral deposits) straddle international borders, each country has ownership of the deposits on its side of the border. It normally makes more commercial and technical sense if such fields are developed by an operator as a single unit rather than as two or more developments under different operators. Countries may enter into unitisation agreements or joint development agreements to achieve this.

1.4.2 Rights to production

Title to Production. Production sharing agreements generally assign title to any production due the oil company at some point in time. That point in time can be at the wellhead or some other point downstream of the well. The tax issue that can evolve is when the title transfer takes place – at the wellhead, at the point of export, or somewhere between the two. Some countries make a distinction between mineral rights (ownership of minerals in the ground), mining rights (right to bring the mineral to the surface) and economic right (ownership of minerals produced and brought to the surface). The point in time when the transfer takes affect can be an issue where VAT is involved and whether it should be applied to any production used to fuel surface facilities used to produce oil and gas. The PSA may specifically exempt such production from taxation. The issue that can arise is whether it is exempted or not, whether it is exempted from VAT or income tax only and whether the intent of the contract was to exempt such production from VAT whether explicitly stated or not. In general, the international practice is to exempt such production from taxation.

1.4.3 National ownership and control of natural petroleum resources

Governments generally pass laws asserting national ownership of all mineral resources. Private companies and individuals can then carry out petroleum (and other mining) operations only if licensed to do so by the government in accordance with statutory rules. Responsibility for administering those rules is normally allocated to a government department with overall responsibility for the industry. In some countries, the government grants sole rights to carry out petroleum operations to a National Oil Company (NOC), which can then enter into licence agreements with private companies.

1.4.4 Legislation and regulations

In some countries fiscal terms and regulations applying to the industry are, to a greater or lesser extent, contained in the same legislation and regulations as those governing management of the industry. In many countries fiscal and operational regulation are also closely linked organisationally, with the petroleum ministry (and sometimes the NOC) not only overseeing the industry but also playing a major role in the formation of fiscal policy for the industry and in the practical administration of fiscal regulations.

1.4.5 Petroleum Authority or Ministerial responsibility

The responsibility for regulation of the petroleum industry may be appointed to a particular ministry or other petroleum authority entity. In practice, such a ministry or authority is responsible for

- Promoting petroleum exploration and development
- Managing the licensing regime
- Negotiating agreements and setting out the terms attached to licences (with input from other departments)
- Overseeing the conduct of petroleum operations
- Providing technical advice or input to the government and the industry

1.4.6 The licensing regime

For the purpose of licensing, most countries divide their geographical territory into separate licence areas or blocks. The term Contract Area is generally used to describe a licensed area.

Companies are initially awarded exploration licences with respect to these blocks. The maximum duration of an initial exploration licence will be specified for the license and generally, it can be renewed subject to certain limitations (e.g. maximum of two occasions for periods not exceeding some period of time in years).

Where a company makes a commercial discovery it can apply for a production licence. The production license may state a maximum duration and be subject to renewal thereafter or for as long as oil and gas is produced.

For exploration licences, licensees typically submit detailed work programs and budgets for approval and agreement by the government entity regulating them. For production licences they also submit a detailed development plan for approval by the government. There are extensive rules regarding data confidentiality, maintenance of records and rights of inspection.

Licensees are permitted to surrender part of the contract area, so long as they meet their work obligations. They are also generally required to surrender or relinquish part of the area on renewal of a licence. This allows the government to re-license parts of an area that are not in practice being explored or developed. The petroleum authority sets out rules governing termination of licences, designed to ensure that exploration and development occur in accordance with licence agreements and government policy. There are also rules governing transfers of licence interests, which have to be approved by the government.

Where a commercial discovery spans more than one contract area the petroleum authority can require the licensees to develop it as a unit under a single development plan.

1.4.7 Operational oversight

The petroleum authority entity and its associated regulations give the government extensive rights of technical oversight and supervision of operations, covering for example:

- measurement and reporting of production
- oversight of installations and works
- oversight of drilling operations
- protection of the interests of other land users

- health and safety procedures
- environmental protection
- abandonment and decommissioning of oilfields
- training obligations
- obligations to use local goods and services.

1.4.8 License award procedures

There is considerable variety between countries in license award procedures. Essentially there are three broad approaches:

Open bid—fixed terms

Under this approach fiscal terms are not biddable, but set by law. Licenses are awarded in a sealed bid process on the basis of work program and/or expenditure bids.

Open bid—variable terms

Under this approach licenses are allocated in a sealed bid process based on various bid parameters including not just work programs but also fiscal terms. In some cases the biddable parameters are limited – for example to signature bonuses – and the approach is not all that different from the previous one. In others they are extensive and may include bonuses, royalty rates, profit oil splits, cost recovery limits, and possibly even tax rates (though generally corporate income tax is a legislated and not a bid item). If many bid parameters are included, comparing bids can be quite complex.

Negotiated deals

Negotiated deals are characterized by the lack of sealed bids or a firm bid deadline, and allow considerable discretion on the part of the government. Though some terms may be fixed, generally a wide range is subject to negotiation. Companies make proposals to the government authority, which ultimately awards licenses to those companies submitting the most competitive proposals.

Many situations do not lend themselves to open tendering and competitive bidding. For example if a country is in the early stages of exploration (or if gas with no local market is considered more likely to be discovered than oil) an open tender for bids may fail because of the high risks and up-front costs, and reluctance on the part of companies to make their interest in the country's prospects public. Negotiated deals are thus common in these situations.

Any of the three approaches outlined above can be subject to risks of government corruption and company collusion. However, generally speaking, the risks are considered greater under the negotiated deal or open bid with variable term approache.Such risks can be controlled in practice through transparency and accountability practices. The latter approaches are less transparent, because, in practice, there tends to be more limited public disclosure of fiscal terms. The amount of disclosure under these approaches varies significantly from country to country. Generally, the petroleum authority may not publish the full details of the license fiscal terms since the petroleum agreements contain strict confidentiality clauses and the disclosure would put an oil company at a commercial competitive disadvantage relative to its potential competitors for the prospective acreage in that country.

1.4.9 Petroleum agreements

Most countries allow the petroleum authority to negotiate agreements with oil companies setting out the terms attached to licences. These agreements take the form of Production Sharing Agreements (PSAs). Production sharing is a type of fiscal instrument used in many countries, particularly in the developing world, but the PSA is not merely about production sharing. It is a comprehensive agreement setting out the regulatory framework within which oil companies must operate. Many of the provisions are concerned with the detailed application of the licensing regime and rules for supervision of petroleum operations discussed above.

The PSA also sets out the fiscal regime. It incorporates the rules for calculating production sharing and royalty, and also incorporates other fiscal terms (e.g. work programs, bonuses, surface rentals and education or training requirements). It also will generally set out income tax rules that will apply and this can be a source of problems if such rules differ from those outlined in the tax code. It also contains fiscal administration regulations on accounting and record-keeping, audit and dispute resolution.

1.4.10 Government equity participation

The PSAs entitle the government to take an equity share in petroleum developments as a Joint Venture participant.

1.4.11 Liaison and exchange of information

A country's petroleum authority is often largely responsible for fiscal regulation of the industry but there should be liaison and exchange of information between the petroleum authority and the ministry responsible for tax administration.

Areas where documentation filed by an oil company with the petroleum authority which will be relevant for factual development of tax issues include:

- Exploration licences awarded and percentage interests (and supply copies of the relevant Petroleum Agreements)
- Cost recovery mechanisms and expense treatment under a PSA
- The contract area and any subsequent changes (relevant for example to the calculation of surface rentals)
- Transfers or other changes of licence interests
- Elections for government participation
- Production licences awarded or determinations of productivity
- Agreed terms for commercial production and sale of gas
- Production volumes and forecasts
- Major oilfield works and developments
- Arrangements for marketing of government petroleum
- Arrangements for production to be allocated directly to domestic use
- Pipeline tariffs
- Agreed abandonment provisions

The petroleum authority should also provide information and guidance on technical issues where requested, for example to assist with oil valuation or tax audit. A common problem that can develop is where a country's National Oil Company is functioning as a regulatory body in permitting or approving oil and gas operations and the NOC refuses to provide documents (e.g. PSA, drilling permits, production filings, well production data, seismic permits, contracts, etc.) to the tax authority. The problem is typically centred around whether the filings made by the oil company with the NOC are subject to confidentiality provisions which may limit access to the documentation and hence prevent the tax authority from reviewing the documents.

1.5 Production Sharing Agreements

1.5.1 Introduction

This chapter provides a general introduction to the use of PSAs in the petroleum industry (sometimes the term PSC or Production Sharing Contract is used instead).

A PSA is a comprehensive agreement setting out the regulatory framework within which oil companies must operate. Many of the provisions in PSAs are concerned with the regulation and supervision of oil operations rather than with fiscal regulation and supervision. This Chapter focuses on providing a general introduction to PSA fiscal provisions.

1.5.2 Model agreements

Some countries publish a model PSA to be used in all cases, with a limited number of variable fiscal parameters to be negotiated on a case by case basis. However, additional variations may be negotiated and the actual PSAs negotiated may contain a number of variations from the model. In practice, the auditor should first become familiar with the Model in order to understand how the agreement is structured and works. The auditor can then identify the specific variations in a particular PSA and study the detailed wording of each PSA relevant for the audit period.

1.5.3 Production sharing

A production sharing regime is often distinguished from a traditional tax and royalty regime, though in practice tax and royalty can be charged in a production sharing regime. (Another type of regime is a service contract regime, where the government simply pays a fee to an oil company or companies to carry out petroleum operations on its behalf.)

Under a traditional tax and royalty regime the government gives a licensee ownership rights over oil discovered and produced, and charges tax and royalty on the licensee's profits and production. Under a PSA the government retains ownership of petroleum resources in the ground but appoints a contractor to assist in developing those resources. Instead of paying a fee for this service the parties agree that the contractor will meet all the costs in return for a share of the production that may result. The contractor has no right to be paid if discovery and development do not occur. If oil is produced the contractor is allowed to retain part of the oil to recover its costs ("cost oil" or "cost recovery oil") and also a share of the remaining oil ("profit oil") determined by a formula set out in the PSA. The term "profit oil" and "cost oil" are generally used in PSAs, and the same production sharing principles generally apply to gas.

Normally PSAs provide for a range of production sharing ratios. The basis for the production sharing ratios varies from country to country (and sometimes from one PSA to another within a country). A common approach is for the government's share of profit oil to increase in line with the level of production. In other countries the government's share of profit petroleum is intended to increase in line with profitability. (Profitability may of course be linked to the rate of production, but there are other important factors that affect profitability – for example, petroleum prices, and the ratio of prices to costs in a particular contract area – so the relationship between production level and profit is generally not exact.) There are different methods of trying to link production sharing to profitability. One is production sharing based on rate of return (ROR). Another is production sharing based on the ratio of revenues to costs (usually called R Factor production sharing).

1.5.5 Cost recovery limits

Normally cost petroleum is limited to a maximum percentage, set out in the PSA, of oil produced – i.e. a cost recovery limit. (The cost recovery limit for gas may be different from the one for oil). The effect of this is that from the beginning of production a minimum proportion of petroleum produced is treated as profit petroleum of which a share goes to the government. The effect is therefore the same as a royalty on production. PSAs may provide for both cost recovery limits and royalties i.e. two separate means of ensuring government revenues as soon as production starts.

1.5.6 Assets used in petroleum operations

Under many PSAs all equipment acquired by the contractor for the purpose of petroleum operations immediately and automatically become the property of the government upon arrival in the country. Under other country's PSAs, equipment acquired by the contractor becomes the property of the government only if the government requests it and only on the earlier of

- the termination of the PSA, or
- the asset being fully depreciated for income tax purposes.

1.5.7 Role of the Petroleum Authority or National Oil Company (NOC)

In many countries the PSA is an agreement between the contractor and an NOC acting on the government's behalf. The NOC may be responsible for the entire regulation of the PSA, or it may have a more limited role. The PSA allows the government to appoint a government-owned company, ministry or other entity as its nominee. It is intended that the governmental entity's role will be limited to disposing of government petroleum and managing any government equity participation.

1.5.8 Marketing and sale of government profit petroleum

Government profit petroleum is in economic substance a tax (and in this manual the term petroleum taxation always includes government profit petroleum).

In most PSAs the government or NOC has the right to take delivery of government profit petroleum, but can instead require the contractor to dispose of it on the government's behalf. Where the government or NOC does take delivery of government profit petroleum (which happens in many PSA regimes), then in effect production sharing is a tax paid in kind rather than cash. The government or NOC then has to market and dispose of the petroleum.

The PSA may allow the contractor to take delivery of some or all of the government's profit petroleum and pay the government for its value, subject to the government's right to retain petroleum required for domestic purposes. So it is possible that the government will not have to market any profit petroleum on its own. If the government does decide to market its share of production, the petroleum authority or NOC will carry out this function on its behalf. Alternatively the government can require the contractor to market and dispose of its share of profit petroleum in return for a negotiated fee.

The PSA may also give the government the right to require payment of royalties in kind (i.e. as a proportion of petroleum produced) rather than in cash.

1.5.9 Profit petroleum and income tax

In most PSA regimes, the contractor is subject to income tax on its profits from petroleum operations. (In some PSA regimes, income tax is also payable by the contractor on the government's production share.)

In some countries the income tax base is identical with the base for profit petroleum (in other words profit oil, or the contractor's share of it, is the measure of income tax profit); in others the bases are closely aligned; and in others they are quite different.

1.5.10 Other taxes and duties

PSAs often include other duties payable to the government, such as bonus payments, royalties, and minor licence fees such as annual surface rentals and education levies.

1.5.11 Accounting rules and procedures annex

PSAs typically require operators to keep separate accounting records for each license area. The detailed principles and procedures for record-keeping, for accounting for costs, and for audit of the operator's records are set out in an Annex to the PSA, which usually also covers taxation issues.

1.5.12 Reasons for adopting PSA regime

Most petroleum producing countries in the developing world have PSA regimes. A traditional tax and royalty regime can be designed to achieve exactly the same government revenues as a PSA, so why are PSAs so popular?

- One reason may be that they use as their model the JOA, a well-established and internationally consistent form of agreement used by oil companies, which is tried and tested, and familiar to, and well-understood by, oil companies.
- Another advantage is that PSAs bring together all operational, financial and tax requirements in a single document, which may be simpler for companies and government authorities alike.
- PSAs are also often considered to give IOCs greater protection against the risk that once they have committed large investments to a country the government will change the terms on which they operate. They form a contract between the government and the IOCs, and normally provide for international arbitration under contract law in cases of dispute. They often also contain stabilisation clauses, intended to protect IOCs from being adversely affected by changes in domestic law.
- Governments may prefer PSAs from a nationalist viewpoint because IOCs can be presented as acting as mere contractors to the government, and not as having acquired property rights over the nation's petroleum.

- Governments may also find PSAs give them greater flexibility in negotiating appropriate fiscal terms for different licence areas. (A criticism sometimes made is that they are therefore less transparent, particularly since the negotiated terms are often kept secret.).
- Governments may also adopt PSAs based on perceptions (e.g. other countries use them instead of concessions so they must know something we don't).

PART 2 PETROLEUM TAXATION

2.1 Outline of Petroleum Taxation

2.1.1 Introduction

This manual is mainly concerned with the special taxes applying to upstream operations, summarised in the manual as petroleum taxes. (Tax legislation uses the term Government petroleum revenues to describe these taxes plus government profits from equity participation).

Government petroleum revenues are

- Royalty
- Production sharing government portion
- Income tax
- Signature bonus, surface rental and education levy

Income tax is a general tax applying to all businesses, but income from petroleum operations included in an income tax assessment may be calculated separately according to various special rules.

The manual does not consider taxation of downstream operations, such as distribution and retail sale of petroleum. In general downstream operations are subject to the normal business tax regime. The PSA generally may state that any pipeline operations will be carried out by a special pipeline company and that it will not be subject to petroleum taxes. The PSA may also state that any refinery operations will also be carried out by a separate company which is not subject to petroleum taxes. (It is possible that a different, special tax regime will be developed for either or both of these companies.)

Companies carrying on petroleum operations (described as contractors in the tax legislation and as licensees on the PSAs) are subject to various normal business taxes, such as withholding taxes on dividend and interest payments, and VAT (summarised as non-petroleum taxes), as well as income tax under normal rules on any income not derived from petroleum operations. Some special rules may apply to withholding taxes payable by contractors.

PSAs may contain a stabilisation clause under which, if there is any change to the laws or regulations that materially reduces the economic benefits derived by the contractor company, the terms of the PSA must be amended to restore it to the same economic position as before the change in law or regulation.

2.1.2 Petroleum tax policy

The general aim of petroleum tax policy is to maximise the benefit to the country from the exploitation of its non-renewable resources while providing sufficient financial incentive to encourage oil companies to undertake high risk and expensive exploration operations. Exploration risk reduces as greater knowledge is gained of an area's prospectivity, but uncertainty about future prices and costs inevitably remains. There is a great deal of theoretical debate about what kind of petroleum tax policy achieves the best balance between the competing objectives of governments and oil companies in these circumstances. This manual does not consider such broad questions, but for those who are interested a general discussion of such issues can be found in the IMF *Handbook on Oil, Gas and Mineral Taxation* (to be published around February 2010), which also contains numerous references to other sources.

2.1.3 Petroleum taxes

The main petroleum taxes are

- Royalty;
- Government profit petroleum;
- Income tax on petroleum operations.

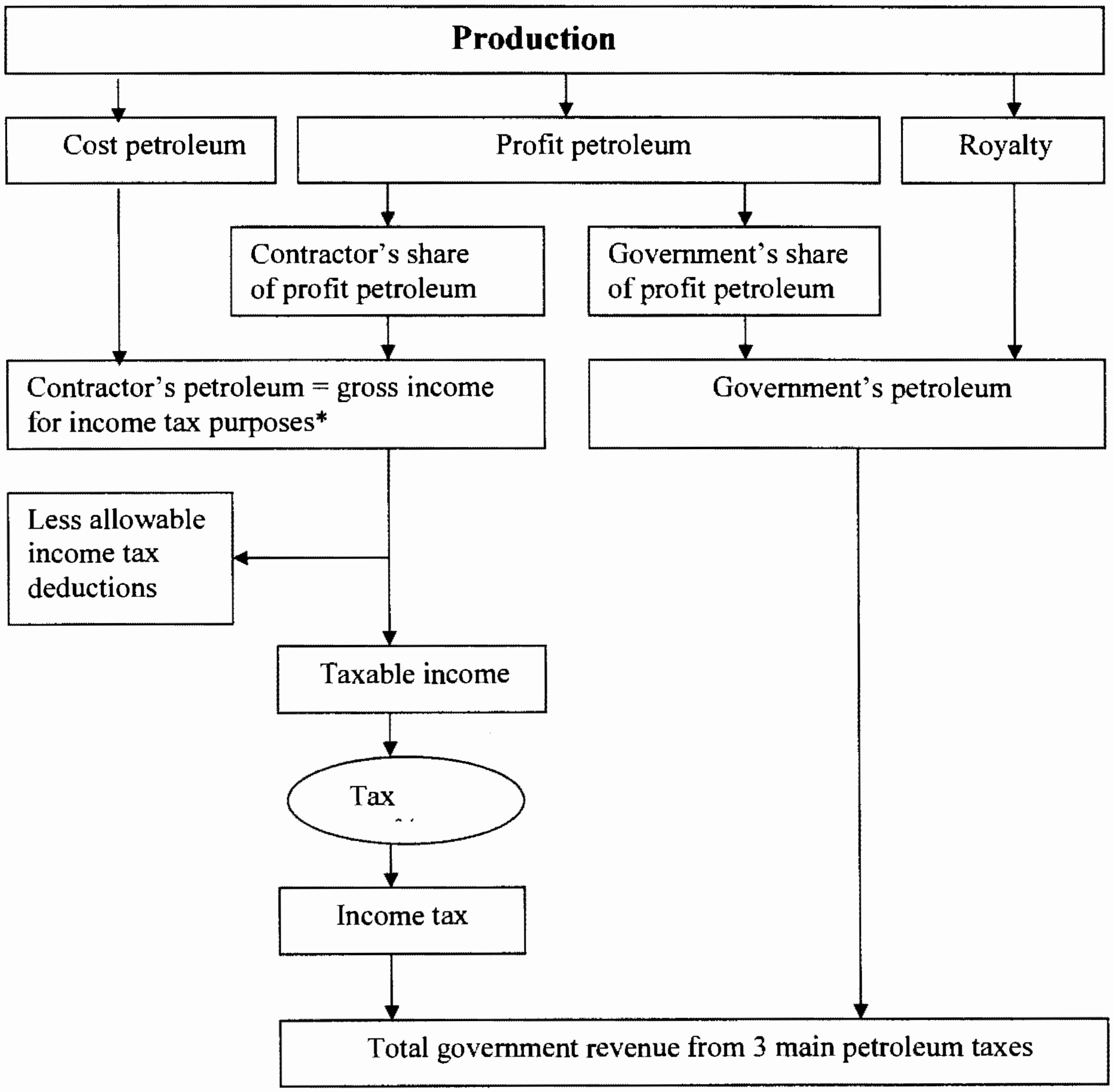
Other government revenues from upstream petroleum operations that are also petroleum taxes in substance are:

- Signature bonuses and other licence fees
- Surface rentals;
- Education levies.

In addition the government receives profits from any equity participation.

2.1.4 Interaction of different taxes

The following diagram sets out the interaction between the three main petroleum taxes of royalty, production sharing and income tax.



Royalty is charged on gross petroleum production. Gross production less royalty is the starting point for calculating profit petroleum. Cost petroleum (costs after application of cost recovery limits) is retained by the contractor, leaving profit petroleum split to be between the contractor and the government. The total contractor's petroleum (cost petroleum plus contractor's profit petroleum) can be thought of as the contractor's gross income from which allowable costs are deducted to arrive at the income charged to income tax. Note, however, that the PSAs state that contractors must pay royalty to the government, so it could be argued that gross income includes royalty. Royalties can only be deducted for tax purposes if paid out of gross income, so if gross income is interpreted as including royalty, companies can deduct royalty as an expense, but if it is interpreted as excluding royalty they cannot.

Allowable income tax costs are broadly the same as recoverable costs before applying cost recovery limits, but with capital costs subject to capital allowances instead of being written off. Ignoring that difference, the relationship of the different taxes can be presented as follows:

Not to scale

Total Government Petroleum Revenue

- **Royalty**
- **Government share of profit petroleum**
- **Income tax on company's share of profit petroleum**
- **Fees, rentals, etc.**
- **Government profit from equity participation**

Taxes other than the three main petroleum taxes are included in recoverable costs (subject to cost recovery limits) for the purpose of production sharing, and are allowable deductions for income tax, apart from bonuses, where the position is more complicated.

2.1.5 Royalties

A royalty is calculated on the basis of total production. Royalties can also be paid based on a sliding scale based on production. Sliding scale structures could be a temptation to a contractor to limit production to minimise tax, or even to manipulate the figures. For example, assume a sliding scale royalty of 7.5% on production from 0 to 15000 barrels and 10% if production exceeds 15000 barrels. If production is 150001 barrels, all production would be subject to royalty at 10%. Clearly this would make production of that extra barrel very expensive for the contractor, and could be a temptation to restrain production or alter production records.

In practice, PSAs are often negotiated such that royalty is calculated on an incremental basis. So in the above example if production for June was 150001 bpd, then the first 15000 would be charged at 7.5%, and the final 1 bpd at 10%. Clearly, it is important to ensure that royalty is calculated on the basis actually applied by the PSA concerned.

2.1.6 Production sharing

Oil production sharing is based on profit oil, which is gross production less royalty less recoverable costs. The PSA may provide that production sharing ratios apply on the basis of <u>total</u> production, but in PSAs actually negotiated they are applied to <u>incremental</u> production.

A similar issue can arise as in the royalty example above. If the PSA wording which specifies how production is calculated and allocated between the parties is unclear, then problems can arise. The auditor should have a good understanding of how production calculations work under the PSA.

As with royalty, the PSA may provide that the government has the right to receive payment of government profit oil either in kind or in cash (e.g. US dollars), depending on its preference. The PSA could also provide that the contractor may take and dispose of the government's profit oil, apart from any required by the government for domestic use, and pay its equivalent value.

2.1.7 Recoverable costs – ring-fencing

A concept, which has been developed in calculating profit petroleum, is that only costs relating to a particular contract area are recoverable against petroleum revenues from that area. This concept is referred to as "ring fencing" and the applicable contract area is said to be "ring-fenced". The result is that there can be no consolidation of revenues and costs for different licence areas. This principle also applies for the purpose of income tax, as discussed below. The effect of ring-fencing is that companies have to calculate profit petroleum and income tax separately for each contract area in which they have an interest.

Note that under a typical PSA, the area included in the contract area varies through time. The original license area may decrease over time as portions are relinquished. At the effective date of the agreement, it is the area described in the agreement, and on any later date it is so much of that area as remains subject to an exploration or production license granted to the contractor. So if a contractor incurs exploration expenditure in a part of the contract area that is later relinquished, that expenditure is still contract expenditure and can be recovered from contract revenues arising in a later period from the area that has not been relinquished.

Ring-fencing can be applied in a number of ways. The most common is on a field basis or a block basis. On a field basis the ring-fence is around the field and a problem can arise for the oil company concerning expenditures incurred prior to or outside a productive field. An example is the treatment of dryhole costs for wells drilled prior to the discovery of a productive field. The effect of the field basis ring-fence would be to limit the deductibility of those costs as an immediate expense and potentially require them to be capitalized. This has a potential adverse impact on the economics of oil and gas exploration and development. On a block basis, the ring-fence is around the entire block that is awarded and the adverse impact previously outlined is avoided. On a block basis such costs were incurred within the block and thus would be deductible as a current expense. The auditor should examine the PSA to determine how ring-fencing is applied and whether it is on a field or block basis.

2.1.8 Recoverable costs – cost recovery limits

Cost petroleum is subject to cost recovery limits. These are expressed as a maximum percentage of petroleum produced, net of royalty. The percentage specified in the Model PSA is 50% but the percentage specified in actual PSAs may be different. (The cost recovery limit for gas may be different from that for oil, or may be left for future agreement.)

Note that it is a cost recovery *limit*, not an *entitlement*. If costs are lower than the cost recovery limit, then the cost recovery is limited to the actual costs.

Example

Petroleum revenues in the year, net of royalty, are $100m and costs are $40m. The cost recovery limit is 50%. Although the limit would allow up to $50m (i.e. (.5) ($100m)) in cost recovery, the actual costs are only $40m. The profit petroleum is therefore $60m. If the cost recovery limit is not used up, the unused balance becomes profit petroleum.

Costs in excess of the cost recovery limit are carried forward to later years and recovered in those future years subject to the cost recovery limit.

Example

In year 1 petroleum revenues, net of royalty, are $100m and costs are $75m. The cost recovery limit is 50%. Profit petroleum is therefore $50m, and $25m costs are carried forward as unrecovered costs.

In year 2 net petroleum revenues are again $100m and costs for the year are $35m. These costs are increased by the $25m unrecovered costs brought forward from the previous year, but because of the cost recovery limit only $50m costs can be recovered in year 2, so $10m costs are carried forward.

Below is a simplified example in a table format of Cost Oil and Profit Oil calculations in a PSA. Note that in year 0 there is no production and thus no revenue or royalty due. However, there is $200 in costs incurred but no cost oil to recoup these expenses from. In year 2, there is production and an additional $600 in costs bringing the cumulative costs to $800 = $200 + $600. This example uses a Cost Recovery (CR) annual limit of 50% of production. Due to the cost recovery limit, if gross revenues are $1000 in a given year, only $500 of the accumulated costs can be deducted in that year and the remaining amount is carried forward. The costs in this example would typically include a depreciation allowance for the capitalized costs + operating expenses. The profit oil is that portion remaining after the deductions for cost recovery and royalty. The profit oil would be split between the parties pursuant to the terms of the PSA. Note that the total costs incurred over the 5 year period are $1400 (column G) and the total cost recovery over that same period is $1400 (column H).

Yr	Annual Prod. (BBLS)	Oil Price ($/BBL)	Gross Revenues	20% Royalty	Net Revenue	C/R Limit (50%)	Costs	C/R	CR Carry Forward	Total Profit Oil
	A	B	C	D	E	F	G	H	I	J
0	0	$100	$0	$0	$0	$0	$200	$0	$200	$0
1	10	$100	$1,000	$200	$800	$500	$600	$500	$300	$300
2	10	$100	$1,000	$200	$800	$500	$400	$500	$200	$300
3	10	$100	$1,000	$200	$800	$500	$100	$300	$0	$500
4	10	$100	$1,000	$200	$800	$500	$100	$100	$0	$700

If insufficient petroleum is produced to allow recovery of costs in excess of cost recovery limits, then the excess remains unrecovered.

(Note that the existence of cost recovery limits can result in ambiguity about the meaning of the term "recoverable costs". Sometimes it is used to mean potentially recoverable costs – i.e. all the costs that can be recovered under the terms of the PSA ignoring cost recovery limits. Sometimes it is used to mean costs actually recoverable in a particular year – i.e. costs within cost recovery limits. To avoid confusion, bear this potential ambiguity in mind when using the term in discussions.)

2.1.9 Recoverable costs – government equity participation

Under the terms of a PSA, the government or its nominee may be entitled to take an equity participation in a development area, up to a maximum percentage (e.g. 20% or some other stated amount). The costs of the government's participation are to be "carried" by the licensee from development through to production. This means that the licensee pays the government's pre-production development costs. These costs are recoverable by the licensee along with interest at London Inter-bank Offered Rate (LIBOR) from the date the costs are incurred up to when they are recovered. The PSA may provide that they are recoverable from some stated percentage (e.g. 60%) of the government's share of cost oil, i.e. from the oil that the government would have been able to retain to meet these costs if it had borne them. However the details and wording of such negotiations or modifications to a model form PSA may not appear in actual PSAs negotiated. Such details may be in side agreements or through informal arrangements with the petroleum authority or NOC.

If the government equity participation is held by the country's NOC, it will be for NOC to agree with the licensee the details and timing of recovery of these costs. The following example is intended to illustrate the broad principles involved, for simplicity ignoring the 60% limit mentioned above.

Example

In year 1 the government elects to take a 20% participation in a development area, to be held by NOC. Production commences at the start of year 3, and cumulative development costs up to commencement of production are $500m as shown below. Results for years 1 to 6 are as follows:

	Production	Costs
Year 1	0	$250m
Year 2	0	$250m
Year 3	$250m	$200m
Year 4	$300m	$50m
Year 5	$400m	$50m
Year 6	$400m	$50m

NOC's share of the $500m development costs up to the commencement of production ($500m x 20% = $100m) is "carried" by the licensee, who thus bears the whole of the $500m costs. The licensee is entitled to retain all the cost recovery petroleum required to recover the $500m pre-production costs. Post-production costs are then met 20% by

NOC, which becomes entitled to retain 20% of the cost recovery petroleum required to meet its share of those costs. This does not affect the calculation of profit petroleum and income tax, but 20% of those taxes is payable from the outset by NOC in respect of its equity interest. Cost recovery remains subject to normal cost recovery limits.

So to continue the example, if the cost recovery limit is 50%, profit petroleum based on the above figures is:

Year 1	0
Year 2	0
Year 3	\$250m – costs \$125m = \$125m, costs c/f \$575m
Year 4	\$300m – costs \$150m = \$150m, costs c/f \$475m
Year 5	\$400m – costs \$200m = \$200m, costs c/f \$325m
Year 6	\$400m – costs \$200m = \$200m, costs c/f \$175m

Thus, because of the cost recovery limits, the \$500m pre-production costs (borne and recoverable solely by the licensee) are not recovered until part way through year 6, and the post-production costs (borne and recoverable 80% by the licensee and 20% by NOC) do not start to be recovered until part way through year 6.

Assuming the government's share of profit petroleum is, say, 60% each year, the government's share is calculated in the normal way as follows, but 20% is payable by NOC in proportion to its equity interest:

	Total	Licensee	NOC
Year 3	\$125m x 60% = \$75m	x 80% = \$60m	x 20% = \$15m
Year 4	\$150m x 60% = \$90m	x 80% = \$72m	x 20% = \$18m
Year 5	\$200m x 60% = \$120m	x 80% = \$96m	x 20% = \$24m
Year 6	\$200m x 60% = \$120m	x 80% = \$96m	x 20% = \$24m

Both the licensee and NOC also pay income tax in accordance with their equity interests. As mentioned earlier, the licensee is also entitled to recover interest at LIBOR on the carried costs.

2.1.10 Income tax

Some countries have a different income tax rate for natural resource extraction (e.g. income from petroleum operations).

Chargeable income from petroleum operations for the purposes of income tax is gross income less allowable expenditure. Gross income from petroleum operations is, broadly speaking, the value of production less government profit oil and royalty, and production is valued in the same way for income tax as for production sharing. Allowable expenditure for income tax purposes is, broadly speaking, the same as recoverable expenditure for production sharing purposes, except that:

- deductible costs are not subject to cost recovery limits
- capital development costs are depreciated subject to any restrictions

2.1.11 Income tax – losses

Income tax losses from petroleum operations are calculated on the same basis as chargeable income, and can be carried forward without limit for set-off against later income, subject to the ring-fence rules and tax code.

Because for income tax purposes costs are not subject to cost recovery limits and capital costs are depreciated, excess costs carried forward for income tax purposes will be quite different from unrecovered costs carried forward for production sharing purposes.

Example

In the first year of production the value of petroleum produced is $110m. Royalty is $10m. Recoverable expenditure to date is $300m, $60m of which is classified as allowable operating expenditure for income tax purposes (including exploration expenditure) and $240m as allowable capital expenditure (including pre-production development expenditure).
Production sharing is calculated as follows (assuming a 50% cost recovery limit and a 50:50 profit split):

Production net of royalty	$100m
Recoverable costs limited to $100m x 50%	$50m
Profit oil	$50m
Contractor's profit oil $50m x 50%	$25m
Recoverable costs carried forward $300m - $50m	$250m

Income tax on the contractor is calculated as follows:

Gross income		
(cost petroleum $50m + contractor's profit oil $25m)		$75m (net of royalty)
Less - operating expenditure	$60m	
- capital allowances $240m/6	$40m	$100m
Excess costs carried forward		($25m)

2.1.12 Income tax – ring fencing

There is no separate income tax on income from petroleum operations, even though special income tax rules apply to that income. It is charged to income tax along with other income. But the ring-fence principle applies to income tax in the same way as to production sharing. The tax auditor should note any Consolidation Principles, listed under any annexes to the PSA, and references in the PSA or annexes that income tax is assessed on the basis of Aggregate Contract Revenues and allowable Contract Expenses. This does not necessarily mean that Contract Expenses for one Contract area can be set against Contract Revenues from another area. Also note any legislation, PSA provisions or tax code regulations implying or stating that the ring fence principle is to apply to income tax. Income from each contract area and from non-petroleum operations must be calculated separately to ensure that contract costs relating to a particular licence area can be allowed only against revenues from that license area, and losses relating to a particular area can be carried forward only against later profits from that particular area.

Example

	Contract Area 1	Contract Area 2	Contract Area 3	Non-petroleum Income

Revenues	$50m	$50m	$5m	$2m
Allowable costs	$30m	$25m	$20m	$3m
Income tax profit	$20m	$25m	-	-
Loss carried forward	-	-	$15m	$1m

Profits subject to income tax for the year are $45m, and the losses carried forward can be deducted only against future years' income under the same headings. Note that, in effect, this means that revenues and costs

- from each contract area, and
- from non-petroleum activities

must be calculated separately.

Note that differences between how a contract area is defined in a PSA and how it is defined in the tax code can cause problems. The PSA may state the costs are ring fenced by contract area where contract area is defined as the area remaining after portions have been relinquished over time. The tax code may define contract area as the area originally licensed and not take into account portions which have been relinquished.

2.1.13 Minor petroleum taxes: signature bonuses

In some country's PSAs the contractor has to make a signature bonus payment to the government when the license is executed (i.e. agreement is signed by the respective parties). Bonuses can also be charged on other events, such as the award of a production licence. In countries where prospects of finding oil in licence areas are seen as being very good, signature bonuses can be very substantial (though the amount companies are prepared to pay will also depend to some extent on the fiscal regime that will apply).

Signature bonuses may or may not be recoverable for the purpose of production sharing and will depend on the PSA. Signature bonuses may be deductible for income tax purposes or they may be required to be capitalized under the country's income tax rules.

2.1.14 Minor petroleum taxes: surface rentals

These are rental payments charged per unit area (e.g. acres, hectare, square kilometres, etc.) of the contract area. The amount of the rent is set out in the PSA, and generally increases from one exploration period to the next, and increases substantially if a production licence is granted. The rent is payable in advance and without demand on the date the licence is granted and on subsequent anniversary dates. There is no refund when a licence terminates mid-year unless specified otherwise in the PSA.

Example

Say that an exploration licence for a contract area was granted on 1 January of Year 1, and a production licence was granted on 1 April of Year 3. Rentals appropriate to the exploration licence would be payable on 1 January of Years 1, 2 and 3, and there would be no refund of any of the rental paid on 1 January of Year 3. Rentals appropriate to the production licence would be payable on 1 April of Year 3 and subsequent years.

Bear in mind that the area by reference to which surface rentals for a contract area are payable will reduce if a part of it is relinquished by a company, whether voluntarily or as required by the terms of the PSA.

Surface rental payments are recoverable for the purpose of production sharing and are deductible for income tax purposes.

2.1.15 Minor petroleum taxes: education levies

A PSA may specify fixed charges or tax levies for education. These charges may be set out in the section of the PSA dealing with Training and Employment. Education levies are recoverable for the purpose of production sharing and are deductible for income tax purposes.

2.1.16 Special withholding tax rules

Withholding taxes on payments to subcontractors can be an issue.
A PSA or tax code may set out special rules applying to petroleum contractors or subcontractors. For example:

- The rate of withholding tax applied to a participation dividend paid to a non-resident company may be specified (e.g. 15%).
- The rate of tax applied to a payment to a non-resident subcontractor for services relating to petroleum operations may be specified for withholding at a specified rate (e.g. 15%).
- The rate of tax applied to payments for goods and services made to a resident subcontractor may have to be withheld at a specified tax rate (e.g. 6%).

A question may arise regarding the proper application of any dividend withholding tax requirements. This issue is where a parent Oil Company has a subsidiary in a foreign country and the country wants to apply a withholding tax to dividends paid by the subsidiary to the parent which may be based on the profits of the particular branch/subsidiary. The concern by the Oil Company is that the country tax auditors may apply a dividend withholding tax to the entire distributions from the branch or subsidiary, regardless of whether such distributions are a distribution of profit or a return of capital. Dividend withholding tax or a branch profit remittance tax is normally only applied to remittances of profit and not applied to any portion of the remittance, from the branch to the parent, which is a return of capital.

Another question that may arise concerns the tax obligation arising from conducting some activities in a country where the party conducting the activity may not have a permanent establishment or there is a question as to what constitutes a permanent establishment. The following examples illustrate the issue that can arise:

- How long must an office exist before it creates a permanent establishment?
- Does performing services for a customer in its offices create a permanent establishment?
- Does an independent contractor performing a service in a country create a permanent establishment when the contractor is not a resident of the country?
- What constitutes a fixed place of business?
- If a contractor, who does not have a fixed place of business in a country, conducts a service in that country and stays a short period at a hotel or other type of temporary dwelling, does the hotel or temporary dwelling constitute a fixed place of business?
- Would a manager, accountant, engineer, lawyer or other type of professional be subject to income tax, in a country they were visiting for a professional education conference or seminar, if they discuss business, advise a government official or conclude a deal?

2.1.17 Stabilization clause

A PSA may contain a stabilization clause. These types of clauses address the situation where there is any change in a country's laws or regulations that materially reduce the licensee's economic benefits. The clause typically specifies that the parties are to meet to negotiate and agree to modifications of the agreement that will restore the licensee's previous overall economic position, with a right to independent arbitration if the parties are unable to reach agreement.

2.2 Petroleum Tax Issues – Oil and Gas Revenues

2.2.1 Introduction

Revenues from disposal of oil and gas are calculated in the same way for royalty, production sharing and income tax on oil operations.

Oil revenues are valued on the basis of volume of production times "Market Price". Market Price is based on the weighted average of sale prices realized where 50% or more of sales by volume in a month are made on arm's length terms; otherwise it is based on average benchmark prices. Calculation of Market Price is to be carried out, and agreed, monthly, and valuations of oil on the basis of those prices are to be carried out, and agreed, quarterly. These valuations must then be used in accounting for oil taxes e.g. for the purpose of preparing annual returns of income tax on petroleum operations.

Note that companies are obliged by paragraph 1.7 of Annex C to carry out all transactions at arm's length prices, and this includes oil sales – but because oil revenues have to be valued for tax purposes on the basis of average and not actual prices, the figures for oil revenues in companies' commercial accounts can be expected to differ to some extent from those in their tax calculations.

Gas is valued either at actual realized price for arm's length sales, or at a price to be agreed between the government and the contractor in other cases.

2.2.2 Volume of production

As explained above, oil revenues are valued not on the basis of actual sales, but on the basis of number of barrels of oil produced times a calculated Market Price per barrel.

Production for valuation purposes excludes petroleum used in operations. This might include for example gas re-injected to increase pressure, gas used to operate as fuel for surface facilities or oil used in the course of wellhead operations.

A PSA may include detailed rules for the physical measurement of the volume and quality of petroleum at the point of delivery. This is a complex and highly technical. Generally, the responsibility for overseeing measuring equipment and procedures to ensure that petroleum is not illegally lifted, and for monitoring petroleum production volumes, normally rests with the petroleum authority. The verification of production and the examination of the equipment involved in the measurement process are sometimes described as physical audits or production audits. It is essential, however, that production data are regularly and promptly provided to the tax administration ministry for the purpose of petroleum valuation issues.

2.2.3 Valuation basis periods

The wording of the valuation rules in the PSA may present some difficulties. For example:

- Where the PSA states that crude oil shall be valued at the end of each Calendar Quarter, but royalty and production sharing have to be calculated and paid monthly. Quarterly calculation and payment is more common for production sharing, but in some cases royalty is calculated and paid monthly, which requires monthly valuation. The PSA may require the Market Price for oil valuation to be determined at the end of each month. So, even if valuation is carried out quarterly, it should be based on Market Price calculated separately for each month within the quarter.

- Calculating the Market Price where arm's length sales have been made in the "preceding month": i.e. the weighted average of the net realized price per barrel obtained for such sales. The "preceding month" might be taken as meaning the month before the month at the end of which the Market Price is to be determined – i.e. the Market Price for June calculated at the end of June should be based on prices in May and the percentage of arm's length sales in May. In general terms, it would not make sense to calculate the Market Price for June on the basis of May prices. Where less than 50% of sales during the preceding month are arm's length sales, then the Market Price could be based on the price of benchmark crudes.

- The situation where most oil is sold on non-arm's length terms. The PSA may state that the basis to be used in those circumstances is the average of the prevailing prices of some specified benchmark crudes. If the majority of sales in, say, July were made on non-arm's length terms, then the Market Price for July should be taken as the average price of the benchmark crudes over the entire Calendar Quarter, i.e. from 1 July to 30 September. It would be impossible at the end of July to calculate the average prices of the benchmark crudes for the 3 months to 30 September.

2.2.4 Market Price of oil – arm's length sales basis

The PSA may state that for any month where some percentage of sales (e.g. 50% or more) of oil by volume are made to third parties on arm's length terms in freely convertible currencies, the Market Price is to be taken as the weighted average of the per barrel net realized price obtained Free on Board (FOB) at the seaboard terminal point of export for those arm's length sales.

The FOB price is the price obtained for the oil on the basis that it is delivered to the buyer when it is loaded on to the ship at the seaboard terminal, with the buyer bearing all costs and risks of loss or damage beyond that point. Alternative commercial bases of pricing are possible, such as, for example, CFR (cost and freight – where the seller must pay the costs and freight necessary to bring the oil to a named port of destination) or CIF (cost, insurance and freight – similar to CFR, but where the seller also has to pay for marine insurance). But FOB prices must be used for the purpose of the PSA valuation rules, and adjustments made if any other price basis has been used. (A summary and definitions of the different possible commercial pricing terms and standards used in international contracts for sales of goods can be found at http://www.iccwbo.org/incoterms/id3040/index.html.)

A PSA may provide that if a separate pipeline company is formed to handle and transport oil from the delivery point in a host country to the seaboard terminal, the FOB price is to be reduced by the average transportation tariff charge per Barrel for that month imposed by the pipeline company (i.e. this cost is to be treated as an adjustment to revenue rather than as a separate cost.)

It is possible that an IOC could set up affiliated oil marketing companies in other countries (including possibly tax havens) and channel sales through such affiliates. Where an affiliate is interjected for no good reason it could be for avoidance reasons. The auditor may want to examine the economic substance of the affiliate and the transactions conducted with it.

A PSA may have provisions that address sales to affiliated companies or restricted or distress transactions or any transactions not at arm's length including government-to-government, barter or discount deals. In general, such transactions could be treated as non-arm's length transactions and be subject to any provisions specifying some percentage test (e.g. less than 50% of sales are sold to third parties) in determining the market price.

The impact of sales to affiliated entities and market price determinations to be used will depend on the wording in the PSA.

Example

a) A company sells 10000 barrels of oil at $50 a barrel on 1 March, 20000 barrels at $60 a barrel on 15 March and 30000 barrels at $70 dollars a barrel on 30 March. All these transactions are on Arm's Length (AL) terms, so the weighted price per barrel is:

$$\frac{(1 \text{ x } 50) + (2 \text{ x } 60) + (3 \text{ x } 70)}{6}$$
$$= \underline{\$63.33}$$

The value of oil produced in the month is therefore $63.33 x 60000 = $3,799,800.

b) Now suppose that the 15 March sale was on Non-Arm's Length (NAL) terms. The majority of sales by volume are still AL, **if** the PSA specifies the NAL sale is disregarded for the purposes of the Market Price calculation, and then it becomes:

$$\frac{(1 \text{ x } 50) + (3 \text{ x } 70)}{4}$$
$$= \underline{\$65}$$

The value of production in the month is therefore $65 x 60000 = $3,900,000.

This illustrates a potential abuse problem in periods of price volatility and how a PSA market price provisions work. A company that would otherwise be in situation a) might deliberately arrange for, say, 180000 barrels of its 30 March production to be delivered to an affiliate at the market price. The majority of sales by volume would still be on AL terms but this NAL sale would be left out of account in calculating the Market Price, which would therefore become;

$$\frac{(1 \text{ x } 50) + (2 \text{ x } 60) + (1.2 \text{ x } 70)}{4.2}$$
$$= \underline{\$60.48}$$

The value of production in the month would now be $3,628,800, so by this simple step the company would have reduced its oil revenues for tax purposes by $171,000, with no effect on its commercial profit.

Some major international oil companies market most of their petroleum through a special trading subsidiary, but this is less likely in the case of smaller IOCs. If a company that normally sells oil direct to the end purchaser chooses on a particular occasion to sell it to an associated trading company, you should consider why it has done this. If it appears to have been done for tax avoidance purposes, the interposed sale to the affiliate should be re-characterized for income tax purposes on the grounds that it was entered into as part of a tax avoidance scheme and had no substantial economic effect.

If a company engages in persistent and aggressive tax avoidance transactions which are contrary to the spirit of the PSA, a report should be made to the country's petroleum authority so that they can consider what action to take.

It can be a useful tool for tax and petroleum authority auditors responsible for oil valuation to develop and maintain a comprehensive database of arm's length prices realized from sales of the country's oil, and prices for similar benchmark crudes of like kind and grade. If a sale price is out of line with normal market prices, then, even if it cannot be demonstrated conclusively that it is a non-arm's length sale, it may be possible to argue that it is in effect, merely by virtue of being at below normal market price, a "discount deal" to be ignored under the terms of the PSA. Note the PSA wording, regarding discount type deals, must address this in order for the argument to disregard the transaction, to be persuasive and valid.

2.2.5 Market Price of oil – benchmark pricing basis

A PSA may specify the Market Price is to be calculated as the average of the price per barrel of similar internationally traded crude oils listed on public trade markets, taking into account differences in point of sale, quality, grade, gravity or sulphur content and any special terms and conditions relating to the sale of such crude oils (again less pipeline transportation tariffs if a separate pipeline company is formed). Similar benchmark crudes could still be significantly different from the oil being valued. A PSA may not specifically provide that any adjustment should be made to the benchmark prices to reflect such differences. Nevertheless, if there are significant differences, appropriate adjustments (up or down) to the benchmark prices should be made.

Ideally, the operating company should be asked to propose and provide data to justify the benchmark prices to be used. The petroleum authority is normally responsible for negotiating any benchmark prices and crude to be used for valuation purposes under the PSA.

2.2.6 Valuation of gas

Natural gas will only be valued where it is capable of commercial development. A PSA may specify it is to be valued at:

- For arm's length sales - the net realized price obtained at the Delivery Point
- For non-arm's length sales - the value determined by agreement between the government and licensee, provided that it reflects:

  i. the quantity and quality of the natural gas;
  ii. the price at which arm's length sales of natural gas from other sources, if any, are then being made;
  iii. the price at which arm's length sales, if any, of natural gas imported are being made;
  iv. the purpose for which the natural gas is to be used; and
  v. the international market price of competing or alternative fuels or feedstocks.

For purposes of arm's length sale determinations, a PSA may exclude not only sales to affiliated companies of the licensee but also sales to the government, any public authority or any other entity controlled directly or indirectly by the government.

"Take or Pay" Contracts

Gas is often sold under long-term "take or pay" contracts under which the buyer is required to make periodic payments for a fixed quantity of gas whether or not those quantities are taken. If they are not taken, the buyer is entitled to demand delivery of the product paid for in subsequent years provided certain conditions are met. There may be uncertainty about when income arises to the seller under these contracts.

Where the gas is delivered, income arises at the time it is sold and a debt is created. Where the gas is not delivered, and the payment received gives the buyer a right to receive delivery of gas at some time in the future, the payment is not income at the time of receipt and does not become income until the gas to which the payment relates is delivered, or the seller no longer has any contractual obligation to supply the gas.

The seller no longer has any contractual obligation to supply the gas where:

- the buyer has not requested delivery of the gas paid for but not delivered by the end of the contract period, including any additional period allowed for its delivery; and/or
- the quantity of the gas paid for but not delivered exceeds the maximum production capacity stipulated in the contract for the unexpired period of the contract.

2.2.7 Marketing of government petroleum

Tax auditors should request from the oil company under audit, the volume and value of petroleum paid or provided in kind to the country's NOC or petroleum authority. The NOC or petroleum authority will be responsible for disposing of this petroleum and paying the proceeds to the government.

If a country has an NOC, it may be required to make a tax return to the tax administration agency showing the value of the government petroleum received, and the proceeds, which should be paid into any government bank accounts set up to receive other petroleum taxes. The rules concerning what marketing costs a NOC will be entitled to deduct, and the method of funding those costs will typically be made by the petroleum authority or by legislation. It is expected that the tax administration agency will be responsible for auditing NOC return, and for ensuring that the difference between the value of petroleum and the proceeds banked is properly reported and accounted for.

If a country's petroleum authority receives income from royalties, profit oil and other funds from petroleum operations, it must show the value of the government petroleum received, and the proceeds, which should be paid into the same government bank account as other petroleum taxes. The rules concerning what marketing costs the petroleum authority will be entitled to deduct, and the method of funding those costs will typically be determined by legislation. The country's treasury inspector general function for internal audits may be expected to be responsible for auditing the petroleum authority accounting and tracking of petroleum revenues, and for ensuring the value of petroleum and the proceeds banked is properly reported and accounted for. Alternatively, the tax administration agency may be called upon to provide or assist in such an audit since their auditors have experience with petroleum accounting practices and audit techniques.

2.2.8 Other revenues from petroleum operations

A PSA or its accounting annex may provide that certain revenues should be credited to the accounts under a petroleum agreement:

a. The net proceeds of any insurance or claim where insurance premia were recoverable.

b. Revenue received from outside for the use of property or assets the cost of which was recoverable.
c. Any adjustment received by the licensee for defective material the cost of which was recoverable.
d. Rebates, refunds or other credits received by the licensee relating to any recoverable charges (but excluding any awards granted to the licensee under arbitration or independent expert proceedings under the terms of the agreement).
e. The actual net proceeds of sale realized from the disposal on an arm's length basis of inventory materials originally charged to the accounts under the agreement and subsequently exported without being used. Where the materials are exported without being sold or are disposed of on non-arm's length terms the amount to be credited is the value of the materials as determined under paragraph the PSA or its accounting annex.

Sub-paragraph d above is very wide-ranging: essentially any revenues that reimburse or make good costs recoverable under the agreement should be credited to the accounts.

Treating these amounts as credits means that they are offset against costs in calculating profit petroleum, not added to petroleum revenues (which could produce a different result because of the operation of cost recovery limits).

2.2.9 Revenues not from petroleum operations

Petroleum contractors may have taxable revenues that do not arise directly from oil operations – for example, financial income – though in practice this will be relatively insignificant in most cases. This income does not affect the calculation of royalty or production sharing but is subject to income tax under normal rules.

2.3 Petroleum Tax Issues – Costs

2.3.1 Introduction

This chapter begins by outlining the general rules for recoverable and allowable costs. In this manual:

- recoverable means recoverable for the purpose of calculating profit petroleum, subject to cost recovery limits;
- allowable means deductible for income tax purposes.

It then discusses some broad general principles to be applied in determining whether costs are recoverable/allowable.

It then considers the classification of costs as capital expenditure or as operating expenditure for income tax purposes, and explains the capital allowance rules for capital expenditure.

It then discusses each of the particular costs identified as recoverable or non-recoverable in the PSAs, and their classification for income tax purposes.

2.3.1 Outline of cost rules

Detailed rules for recoverable and allowable costs are set out in Annex C of the PSA.

Recoverable costs

A PSA or its annex may specify in detail which costs are recoverable, and which are not. The costs listed as recoverable are not exhaustive. Typically, there is a general presumption of deductibility for any costs incurred for the necessary and proper conduct of petroleum operations. This means essentially that a cost is recoverable unless it is

- specifically described as non-recoverable, or
- non-recoverable under any broad general principles set out in the PSA

Allowable costs

Costs recoverable are to be classified for income tax purposes under three headings, and are typically defined in a PSA or its annex as:

- exploration expenditures
- development and production expenditures (broadly, expenditure on development); and
- operating expenditures

Service costs and general administrative costs have to be allocated to those heads.) These classifications are relevant only for income tax.

Expenditures classified as exploration or operating expenditures are allowable operating expenditure for income tax purposes. This means they are deductible in the year in which they are incurred (but the date when expenditure is incurred is based on normal accounting principles, as discussed below). However, a country's tax code may specify that expenditure classified as development and production is a capital expenditure for income tax purposes and is deducted by way of capital allowances. Thus, recovery of the cost may be over some period of time through depreciation, depletion or amortization.

Costs allowable for income tax purposes are broadly speaking the same as costs recoverable for production sharing purposes except that

- recoverable costs are subject to cost recovery limits;
- allowable costs are not subject to cost recovery limits but capital expenditure included in allowable costs is depreciated by way of capital allowances.

The auditor should determine whether the income tax rules set out in the PSA have largely been incorporated in the country's Income Tax Act. The auditor should review case law involving conflicts between legislation and contracts between the government and third parties. Note whether there is a provision in the PSA which specifies that taxes applicable to a licensee shall be in accordance with the country's tax code. Also note whether there is a provision in a country's petroleum legislation which states that in the event of conflict between the income tax code and the petroleum code, the petroleum code shall prevail. The question that will arise is:

- In the event of a conflict between the PSA and the tax legislation, is the tax administration agency bound by contractual constraints regarding tax issues?
- Are tax matters subject to the arbitration clause in a PSA?
- Is the tax administration agency part of the government and thus bound by the contractual provisions of the PSA requiring disputes to be resolved through arbitration?
- Is there a conflict between the country's petroleum legislation and its tax legislation?

In many countries, a PSA cannot override enacted legislation, so if there is any discrepancy between the PSA and the Income Tax Act, <u>in relation to income tax,</u> the Income Tax Act will prevail. However this is not always the case. A country may have petroleum legislation that provides for a PSA and the legislation specifies that in the event of conflict between the income tax code and the petroleum legislation the petroleum legislation prevails. Thus, under the facts and circumstances for a specific case, the PSA may obligate the government to abide by the PSA even for tax controversies.

2.3.2 General principles – no double deduction

Some costs could be argued to fall under more than one of the headings and the auditor must review the PSA and identify which provisions or annex applies. However, there can be no double recovery or deduction of costs.

2.3.3 General principles – allocation of shared costs

The PSA may specify in its provisions or annex that costs that only partly qualify as contract expenses must be allocated in such a manner as to fairly and equitably reflect costs attributable to petroleum operations and to exclude those that are not. Because costs are ring-fenced by contract area for the purposes of both production sharing and income tax, this means that only costs attributable to petroleum operations <u>in a contract area</u> can be allocated against contract revenues from that area.

This is a very important and wide-ranging principle, which must be considered in relation to many of the particular costs discussed later in this chapter. It is relevant where, for example:

- a contractor operates internationally and allocates some of its costs (for example head office administration costs) to its operations in a country;

- a contractor has interests in more than one contract area and allocates costs between those areas;
- a field spans more than one contract area (or country) and costs are allocated under the terms of a unitisation agreement.

There are many different possible bases for allocating shared costs. Some companies may allocate some or all of their costs on the basis of complex cost accounting rules. These may include "time-writing", where support staff record their time spent project by project and those times are each translated to a cost. This is common industry practice for project costs, such as preparation of engineering studies, though it is just one of a number of different methods that can be used. Where a basis such as this is practicable and produces a reasonable result, it may be acceptable for companies to allocate some of their costs in this way. But it may not be practicable for some kinds of cost, for example general administrative services.

Companies may allocate some or all of their costs on the basis of a formula. For example parent company costs may be allocated to subsidiaries on the basis of their relative capital expenditure or the value of their assets. Or costs may be allocated between different contract areas on the basis of relative value of production, or relative size of project Authority for Expenditures (AFE), or in the case of equipment costs, relative time on site, and so on.

It is not possible to set out any universal hard and fast principles for allocation of costs. It is a question of examining the basis for allocating particular costs used or proposed by the company, and judging whether it produces a fair and equitable result, with no foreseeable bias in the company's favour. Clearly some of the bases described above are somewhat simplistic and could result in misallocation of costs, and in that case they should not be accepted. Where a basis is agreed as fair and equitable, it should normally then be applied consistently unless some exceptional change of circumstances makes a change appropriate.

In some circumstances cost allocation can be particularly difficult. For example where there is commercial production of oil and gas from the same field, costs may have to be allocated between them. This may be required because the tax rules applying to oil and gas may be different – for example oil and gas may have different cost recovery limits in some PSAs. It is clearly difficult to allocate costs from a single field against different types of production, and it may be necessary to adopt a reasonable conventional basis of allocation, such as volume or value of production.

Cost allocation may involve a two-step process. For example in the case of head office costs the first step might be to distinguish costs directly relevant to petroleum operations from more remote costs of general company management functions, such as long-term planning, policy, finance and treasury management, and the like; and only after that step has been completed to allocate the operational costs to particular contract areas.

As well as ensuring that the basis of allocation proposed by a company is reasonable, you need to ensure that it does not allow the same costs to be allocated twice. For example, if a company is deducting costs for tax purposes overseas, there must be a reasonable presumption that those costs should not also be recovered or deducted in the host country.

In order to verify the reasonableness of the allocation of costs against contract revenues, it may be necessary to review the accounting policies and records of other parties (such as overseas affiliates). The contractor may claim that it cannot obtain access to this information because of its proprietary or confidential nature. In those circumstances, note whether the PSA or its annex allows the government to require the contractor to obtain at its own expense an audit certificate verifying the charges from an independent auditor of international standing, selected by the contractor and acceptable to the government. In the case of charges by an affiliate, note whether the PSA or its annex allow the government to require the contractor to obtain a certificate from the affiliate's auditor attesting that the affiliate's charges are reasonable and consistently applied and do not contain any profit element. If you require such certificates, you should explain carefully how they are to be worded. (For example you may wish the auditor not only to certify that the allocation of costs is reasonable but also to explain the basis of allocation and confirm that the costs have not been allocated elsewhere for any purpose.)

The burden should, however, be on the contractor to show that the allocation of costs is appropriate and reasonable, and you can request any other information you reasonably require for that purpose. If the contractor is unable to provide reasonable evidence, you do not have to agree to the costs claimed.

When considering allocation of costs, bear in mind that in some cases this is a more important issue than in others. For example if there is a misallocation of costs between two producing contract areas with similar taxation regimes, it may have little practical effect in terms of tax, compared with a misallocation of costs between the host country and foreign-taxed operations. In deciding how much time to put into checking the allocation of costs you should bear in mind how much tax is at risk.

2.3.4 General principles – costs beyond the delivery point

Recoverable or allowable contract costs are limited to those necessary to produce petroleum and get it to the delivery point. The auditor must review the PSA and determine where or at what point in time that delivery point is. In the case of oil, a delivery point may be defined in PSAs as the point at which the crude oil passes through the intake valve of the pipeline or tanker or truck or rail wagon at the terminal or refinery in the host country or such other point as may be agreed in writing. Examples of costs beyond the delivery point are costs of further transportation, costs of marketing and sales, and any other "downstream" costs. Of course contractors may incur such costs (and indeed you may want to question where marketing costs have been charged if you see no evidence of them) but they should be treated as costs not relating to petroleum operations.

2.3.5 General principles – appropriate, necessary and economical

Typically, PSAs require recoverable costs to be "appropriate, necessary and economical", and this is also generally required for costs to be allowable under a country's Income Tax Act. This is a very general requirement. Contractors normally have a commercial interest in minimising costs in order to maximise their profits. (It is possible in theory for a petroleum tax regime to be designed in such a way that by spending a dollar a company can save more than a dollar in tax, giving them an incentive to incur unnecessary costs – a practice often described as "gold-plating" – but this occurs very rarely in practice.) Even so, despite their wish to maximise profit, contractors may incur costs unnecessarily or inappropriately as a result of factors such as inadequate planning, poor technical judgement or inefficient management. The "appropriate, necessary and economical" test enables the government consider whether such costs were reasonable under the circumstances and potentially refuse to allow recovery of such costs.

It will, however, be exceptional for you to seek to challenge costs properly authorised under the PSA solely on these grounds. You do not have, nor are you expected to have, the expertise to second-guess contractors' business decisions. The prime responsibility for government oversight of the conduct of petroleum operations lies with the government's petroleum authority. The tax auditor should not seek to challenge costs on these grounds or on their own initiative without first discussing the matter with the petroleum authority.

There could nevertheless be exceptional circumstances where you might wish to consult with the petroleum authority about the possibility of challenging costs on these grounds. For example, if extravagant expenditures were incurred to provide private benefits for local management that appeared to be in conflict with the interests of the business (possibly even without the knowledge of the company head office or parent company), it could conceivably be challenged on these general grounds, or on the grounds that it was out of line with normal industry practice.

Optional expenditure by a contractor that was only indirectly related to petroleum operations could also be challenged on the grounds that it was not necessary or appropriate (though in such cases it could probably also be challenged on other grounds). (e.g. hedging costs)

As discussed earlier, companies may seek to allocate head office or management company expenditure to petroleum operations, which is only indirectly or distantly related to petroleum operations in the host country. Your main grounds for challenging these costs would be that they were not costs of petroleum operations, but again you might also argue that they were unnecessary or inappropriate.

So although it may be rare to challenge costs solely on the grounds that they are not necessary, appropriate or economical, there may be exceptional circumstances where you should do so and you should consult the petroleum authority as necessary. Where you challenge costs primarily on other grounds, the requirement for costs to be necessary, appropriate and economical may sometimes strengthen your case.

2.3.6 General principles – misconduct or negligence

A country's PSA or Income Tax Act may provide that costs are not recoverable or deductible if they arise from wilful misconduct or gross negligence. Such costs are an extreme example of costs that are not necessary, appropriate or economical, and similar considerations apply. Where a company has suffered fines or penalties imposed by Courts, there may be independent evidence of misconduct or negligence which would justify refusing these costs. Such specific costs may be non-recoverable under the PSA or the country's income tax laws. In any such case, you should consult with the petroleum authority on quantification of the costs to be treated as non-recoverable. Where such independent evidence is not present, it will normally be for the petroleum authority to take the initiative in advising that costs can be challenged on these grounds, and to provide evidence and advice on quantification. In the course of an audit, if you identify on your own initiative, costs you believe should be challenged on grounds of misconduct or negligence not established by the courts, you should always first consult with the petroleum authority before proceeding with disallowing these costs.

2.3.7 General principles – the arm's length basis

The PSA or the Income Tax Act may require contractors to account on the basis of arm's length prices, unless there is written agreement with the government to the contrary. This general principle is discussed in more detail as part of a general discussion of transfer pricing below.

2.3.8 General principles – costs before the effective date

The auditor should review the PSA, petroleum legislation and income tax code to determine whether costs incurred before the effective date (i.e. the date of signing of an agreement) are allowed to be a recoverable or deductible cost. Companies may incur such costs, for example, to obtain seismic studies or other information to help them decide whether to apply for an exploration licence, or to obtain professional help in negotiating licence terms. Whatever their nature, such costs may be non-recoverable if incurred before the effective date. However this will depend on the PSA wording and any legislation restrictions. In general, such costs are capitalized to a project area that is acquired and recoverable unless specifically excluded from recovery. You should be aware of the possibility that companies might try to delay or re-cycle such costs. For example, costs for services might be charged after the effective date even though they had mainly been provided before that date. Or costs might be incurred by head office or a parent company before the effective date and re-charged to the local contractor after that date.

2.3.9 General principles – industry accounting practice and standards

The PSA may specify that petroleum contractors use the accrual method of accounting and this may also be required under the country's the Income Tax Act. Essentially, this means that contractors must account in the same way as any other accrual-basis taxpayer under general income tax legislation. The auditor should note whether the PSA or the country's tax code has special rules governing the year when capital allowances on development expenditure are to commence.

The PSA may state that where there are no relevant provisions in the agreement, accounts should be maintained in accordance with normal practices in the international petroleum industry and generally accepted and recognised accounting standards.

The main "relevant provisions" in a PSA are those concerned with the classification of costs and their categorisation as operating or capital expenditures. The issue considered here is the significance of normal industry accounting standards and practices and their relationship to the "relevant provisions" of the PSA.

2.3.10 Types of Petroleum Costs

The principle aim of a petroleum audit is to review the various types of accounts and costs that are tracked in order to:

- Verify that costs claimed for cost recovery under the PSA are qualified expenditures
- Verify that costs claimed as deductions for tax purposes are qualified expenditures
- Verify that amounts claimed for cost recovery or tax purposes are correct and based on reasonable and sufficient documentation
- Verify that production sales are arm's length transactions and properly accounted for
- Conduct compliance checks to ensure a company is maintaining adequate accounting records in accordance with generally accepted practices in the international petroleum industry

Note that costs may be classified under a PSA as "allowable" or "non-allowable" for cost recovery purposes under the PSA. Such classifications have no bearing on the deductibility

of a given expense for tax purposes. A cost which is "non-allowable" for cost recovery purposes under a PSA may be an "allowable" deduction for tax purposes.

Oil and gas exploration and production is a capital intensive endeavor and the industry has a variety of business expenditures. The seismic and drilling costs can be $5-20 million per exploration site. The capital costs to develop an offshore discovery and build an offshore platform can be several billion dollars.

The PSA and Joint Operating Agreement will have an accounting procedures annex which should be reviewed by the auditor. Below are some typical costs which are reviewed in petroleum tax compliance or joint interest type audits.

Capital allowances

A company incurs substantial expenditures on equipment and facilities during exploration, appraisal and development. Typically, a PSA has a provision that the title to this equipment passes to the government at some point during the life of the PSA. That point can be when the assets enter the host country, when the contractor has recovered its full cost for the equipment or some other specified point in time. A problem can arise regarding companies taking capital allowances (e.g. depreciation) for assets that have title passing to the host country upon arrival in that country. It is a generally accepted accounting practice that a capital allowance is only available to the owner of the asset. The owner of the asset is presumed to have incurred the cost of the asset and accordingly is entitled to cost recovery. However, in this situation the oil company is prevented from taking the full capital allowance for an asset they paid for due to failing the "ownership" test. If the full cost of the equipment does not qualify for a capital allowance under the cost recovery mechanism of the PSA, the portion which does not qualify will still be a cost recoverable item for tax purposes.

Each working interest owner will typically maintain separate accounts for producing and nonproducing properties. Each usually keeps their accounting records in such a manner that the income tax return can be prepared showing each property as a separate operation.

Separate accounts may be carried for equipment and intangible drilling and development costs. These accounts are generally called control accounts and are supported by records which track the area covered by the license, bonus paid, date of the license, term, expiration date, the interest owned, royalty, override, annual rental obligations, other interests, assignments, rental payment record, etc. The total costs of nonproducing properties are recorded in the control account and some companies make direct charges to the nonproducing property records, while others enter charges in a suspense account for accumulation, and then clear the suspense account by a single entry to the nonproducing subsidiary record.

In order to ascertain that all capital costs are included in the oil and gas property records, an analysis of the charges to the property record or to the suspense account should be made. The items which generally appear in these accounts are the bonus, permit filing fees, rentals, travel expense, commissions paid for obtaining the license, geological and geophysical expense incurred covering the area in which licenses were acquired or retained and acquisition costs associated with commercial negotiations and land management. As an oil and gas property becomes productive, the record for accumulated costs is transferred to producing property accounts. When an area is unproductive, the accumulated charges in the account covering that area is transferred to an account for surrendered or relinquished acreage or expired oil and gas property licenses. The accumulated costs for the unproductive acreage which is surrendered, relinquished or expired is generally expensed.

Capital allowances on development costs

The auditor should review the tax and petroleum legislation and determine how development costs should be treated. Although development expenditures typically relate to assets that are entirely tangible, the tax code or PSA may treat development expenditure as an intangible asset merely because this is the means chosen to apply the capital allowance rules contained in the PSA or tax code.

On transportation facilities, capital allowances are given on a unit of production basis. This means that for each tax year any expenditure not yet allowed at the start of the year is divided by the recoverable reserves in the contract area at the start of the year and multiplied by the total number of barrels of oil produced in the year. Estimates of recoverable reserves are subject to a high degree of uncertainty, and are very difficult to audit (even by auditors with greater geological and engineering expertise than is likely to be found in the country's audit staff). Such estimates may furthermore change from year to year, in the light of changing experience of the reservoir, movements in oil prices, developments in technology, etc. Different JV partners could, furthermore, estimate recoverable reserves differently, resulting in them depreciating the same assets at different rates. Faced with such an administratively impractical provision, it is hoped that operators and the country's petroleum authority will be able to agree on reasonable estimates of opening recoverable reserves, which the tax administration agency and all JV partners will use without further argument as the basis for calculating unit of production based capital allowances.

Example of capital allowances based on unit of production

$500000 is spent on transportation facilities. The operator and petroleum authority agree that a reasonable estimate of oil reserves for the contract area at the start of the year is 10m barrels. Oil produced during the year is 1m barrels. The cost written off in the year is therefore $500000 x 1/10 = $50000.

For the following year the expenditure not allowed at the start of the year is $500000 - $50000 = $450000. The agreed estimate of recoverable reserves at the start of the year is now 8m barrels, and production during the year is 0.7m barrels. The cost written off in the year is therefore $450000 x 0.7/8.0 = $39375.

Note that in this example the estimate of recoverable reserves has decreased from one year to the next. When the reserves at the start of year 1 were agreed, it was thought that 10m barrels would be recoverable. But when the reserves at the start of year 2 were agreed it was estimated that only 8m barrels would be recoverable, even though only 1m barrels had been produced in year 1. The estimate could just as easily have increased.

Depending on the PSA or a country's tax code, capital allowance deductions typically commence:

(a) the tax year in which

the capital asset is placed into service, or

if the capital expenditure does not relate to an asset which normally has a useful life beyond the year in which it is placed in service, the year the capital expenditure is incurred; or

(b) the tax year in which commercial production commences from the contract area.

Surface rights

Expenditure on acquiring surface rights is recoverable for production sharing purposes and deductible for income tax purposes. This includes the payment of surface rentals to the government under the PSA, and also other payments a contractor might have to make (to the government or other persons) in order to acquire rights over land or water to enable petroleum operations to be carried out. The PSA cost recovery mechanism (e.g. determination of cost oil) does not include the payment of a signature bonus or other similar payment that might be required for the legal right to carry on petroleum operations.

Classification for income tax purposes

If a payment is made for surface rights to enable exploration to be carried out, it should be treated as an operating expenditure, notwithstanding that the rights may extend into a later period when development occurs. If a payment is made after a production license has been granted to enable development to be carried out it should be regarded as capital expenditure. Once production has started, payments for surface rights should be regarded as operating expenditure, unless they relate to further development (for example development of a new field in a different part of the contract area.

Bear in mind that even if a payment for surface rights is an operating expenditure it should still be accounted for under the accrual basis.

Services

The auditor should review the PSA and tax code to determine if there are any special rules on services provided by affiliates. When it comes to services, it is necessary to "look through" the fees charged by an affiliate for services to ensure that the amount allowable for tax purposes is restricted to cost and that any disallowable components are excluded from the composition of the fees involved.

It may be the case that an offshore plant owned by an affiliated service company is dedicated to a field or fields owned by a sister company in the host country. If a charge is made by the affiliate owning the plant to the host country company which includes a depreciation rate for the plant, such a charge may be accepted provided the depreciation rate reasonably reflects the life of the assets.

Insurance and losses

Consider whether the risks covered by the insurance specifically relate to the license Contract area. If the coverage is provided by an affiliate, consider whether there are any transfer pricing issues (e.g. is the cost comparable to an arm's length transaction).

Legal expenses

Consider whether the PSA or tax code provide any specific disallowance of arbitration costs, fines, etc. or special rules for services provided by affiliates? Costs incurred by lawyers or an oil company's legal department in reviewing project construction or arm's length production sales contracts will be allowable as a cost recovery in a PSA. Conversely, those incurred in relation to license acquisitions may not be allowed as a cost recovery expenditure under the PSA cost recovery provisions for determining cost oil and profit oil. Legal expenses are allowable deductions for tax purposes.

General and administrative expenses

General and administrative expenses are generally referred to as overhead and cover costs to manage, assist or support petroleum operations. The auditor should review the PSA to determine which overhead costs are subject to cost recovery under the PSA. The auditor should note what category a cost is allocated to and whether it complies with any special rules arising from the PSA on allocation (e.g. exploration, development operating). Note that costs which may not qualify for cost recovery under a PSA may qualify as a deduction for tax purposes. The issue that can arise is where the home office allocates a portion of its costs to the subsidiary in the host country.

General and administrative costs and head office costs which are directly incurred for a specific field purpose, (e.g. the costs of the onshore field project team such as the salaries of petroleum reservoir engineers, geologists, geophysicists etc.), and for more general support costs such as secretarial and clerical assistance and office overheads etc. can be deductible. The deductibility will be dependent on whether an appropriate link can be established between such costs and a field purpose and whether the method of allocating them to all of the company's interests is reasonable. The burden is on the company to demonstrate that there is a direct relationship between the overhead expense and the field qualifying purpose. This is not present where the costs in question relate to such activities as maintaining the parent company or preserving its corporate image.

Broadly speaking, the following costs from a home office or parent company which have been allocated to the host country company should be reviewed and potentially treated as disallowable items. The list is not exhaustive and merely gives examples of the types of expenditures which may be disallowable:

- long-term corporate planning
- policy
- public and government relations
- finance/treasury

- tax
- advertising, donations, sponsorship
- entertaining
- legal

Interest and finance costs

Oil companies generally have to borrow large sums to finance their activities. A company engaged in upstream activities may borrow direct from a bank or other financial institution, or may issue loan securities to investors. Alternatively it may borrow from an affiliated company. Normally it is difficult for an oil company to borrow from a financial institution to finance exploration, because of the risks involved. Once a commercial discovery is made, companies are normally able to obtain loans to finance a substantial part of the development costs.

Potential tax advantages of borrowing

It is in an oil company's interest to get tax relief at the highest possible rate for its finance costs. The highest rates of tax paid by international oil companies are generally those relating to their upstream oil activities. In many countries, however, there are restrictions on deductibility of interest in computing tax on upstream activities. If a country does have generous rules for deduction of interest against upstream profits, IOCs have an incentive to ensure that their subsidiaries operating in that country are financed as far as possible by loans rather than equity. (on which dividends and other distributions are not deductible). This will make a large difference to the amount of tax they pay, and will therefore reduce government oil revenues.

If an oil company borrows from a financial institution in the country concerned, the government will be able to tax the interest received by the financial institution, but generally it will be taxed at a lower rate than oil profits, and the financial institution may, furthermore, be able to deduct costs against the interest received.

Restrictions on tax deductibility

The auditor should note whether the country allows interest to be deducted in calculating profit oil as well as income tax. (In many countries development costs are instead increased by a fixed percentage – known as "uplift" – as a proxy for interest. This often creates tax problems of its own.) The independent IOCs operating in the host country may have to borrow extensively to fund their operations in that country. The auditor may find large claims for deduction of finance costs for loans to finance exploration or development. It is important that any restrictions on such deductions contained in country's petroleum or tax legislation are properly applied. The auditor should consider the following:

Are there any restrictions on deductibility of finance costs (i.e. interest, fees) to finance development operations?

Are there any restrictions on finance costs to finance exploration operations?

Do the interest rates and finance charges exceed prevailing commercial rates?

Do any regulations or the PSA provide that interest and finance charges are recoverable or deductible only to the extent that they relate to debt that does not exceed some percentage (e.g. 50%) of the total financing requirement?

Does the PSA or regulations require that loans from affiliates be subject to review and approval of the government to ensure that they are on arm's length terms?

Does the PSA specify that costs relating to any bank guarantees required under the agreement are specifically disallowed for the cost recovery provisions?

Note that the rules under a PSA may be much narrower and more restrictive than normal income tax rules. Consequently, an audit of cost recovery verification may disallow some costs for profit oil calculation while those same costs are allowed as a deduction from gross income for tax purposes.

The following example is to illustrate the situation where a country has specific restrictions on financing arrangements and uses some arbitrary assumptions for demonstration purposes. In this example, exploration finance costs are not deductible and there is a limit on deductibility of finance costs to the extent that they exceed 50% of the total financing requirement. To the extent that production income is available it should be treated as reducing the financing requirement. To put it another way, the financing requirement at any stage should be taken as the negative net cash flow accumulating from operations: as soon as net cash flow turns positive there is no longer a financing requirement.

Example

An oil license is 100% owned by a company. Revenues and costs are as follows:

	Year 1	Year 2	Year 3	Year 4	Year 5
Oil revenues	-	-	$50m	$100m	$150m
Costs – exploration	$10m	$5m	-	-	-
Costs – development	-	$40m	$20m	-	-
Costs – production (opex)	-	-	$5m	$10m	$10m

Taxes paid are as follows:

Royalty	-	-	$5m	$10m	$15m
Government profit oil	-	-	$13m	$31m	$68m
Income tax	-	-	$2m	$12m	$14m

The company borrows $25m at a commercial rate to finance development costs in year 2 and claims a deduction for loan interest paid on the $25m. It borrows a further $10m in year 3, and in years 3, 4 and 5 claims a deduction for loan interest paid on $35m.

Taking account of oil revenues, however, the cumulative financing requirement (or negative net cash flow) at the end of each year is

Year 1	Year 2	Year 3	Year 4	Year 5
$10m	$55m	$50m	$13m	0

For year 1 there is no borrowing (and if there had been there could be no deduction because it would all have related to exploration).

For year 2 the maximum debt on which interest can be deducted is $55m x 50% = $27.5m. This is more than the company borrowed ($10m + $25m), so the interest can be deducted in full.

For year 3 the maximum debt on which interest can be deducted is $27.5m reducing to $25m ($50m x 50%), so the company's claim must be restricted.

For year 4 the maximum debt on which interest can be claimed is $25m reducing to $6.5m ($13m x 50%), so again the company's claim must be restricted.

For year 5 the maximum debt on which interest can be claimed is $6.5m reducing to 0. Again the company's claim must be restricted. Assuming cash flow remains positive, no interest will be deductible for later years under the assumptions used here.

Where the maximum debt on which interest can be claimed varies during the year (as in years 3 and 4 above) and the company must pay taxes monthly, the company should be required to provide a monthly analysis of net cash flow to show the amount of debt on which interest is deductible each month.

Any outgoings that are not recoverable costs should be ignored for the purpose of determining the financing requirement. For example if the company chose to pay dividends these would be ignored in calculating its net cash flow.

It is expected that borrowing and finance costs will normally be shared among joint venture partners in accordance with their equity interests. It is theoretically possible, however, that different joint venture partners might borrow amounts not proportionate to their equity interests. In that case the limits above should be applied to each JV partner individually: interest and finance costs of an individual JV partner should be treated as not recoverable/deductible to the extent that borrowing by that partner exceeds 50% of the financing requirement of that partner.

Finance Costs

Finance costs should be treated as including not just interest but also:

- incidental costs of borrowing such as loan arrangement fees;
- exchange losses on foreign currency borrowing;
- payments under interest rate swaps ;
- discounts, premiums and deferred interest;
- payments under finance leases treated as interest under normal accounting principles.

Interest on carried government equity participation

If the government chooses to take an equity participation in a development area, the PSA may require the licensee to "carry" the government's participation from development through to production, or in other words it must meet the government's pre-production development costs, but it can recover these costs from the government entitlement to oil as an equity participant.

The cost of "carrying" these costs should be treated as part of the licensee's financing requirement but the debt on which finance costs are recoverable/deductible will still be limited to special restrictions on total financing requirement that the tax code or PSA specify.

The PSA may specify that carried costs are recoverable by the licensee and include interest at LIBOR from the day the carried costs are incurred. The value of the oil to be retained by the licensee to recover this notional interest is a matter that must be agreed upon between the licensee and the country's petroleum authority or NOC. The tax auditor need not concern themself with how that amount is quantified, but you are concerned with the tax consequences. The value of the oil retained to meet the notional interest cost should be treated as a credit or receipt in calculating the profit oil and income tax of the licensee, and as a debit or cost in calculating the profit oil and income tax of the NOC.

Research & Development (R&D)

The auditor may want to review any research and development deductions and verify they are subject to the PSA cost recovery provisions that will impact profit oil determinations. Sometimes a company may include expenditures for geological and geophysical costs as an R&D expense. The company may state that these costs pertain to efforts to develop or improve seismic, drilling, or production operations. These costs are normally deductible from gross income for tax purposes.

Abandonment/decommissioning

An oil field (or part of a field) is abandoned when commercial production is no longer possible. At that stage the oil installations must be closed down, and possibly moved, and the environment cleaned and restored to its original state, as far as possible. The PSA typically sets out these obligations and it normally requires companies to carry out the activities subject to an abandonment or decommissioning plan proposal that has been approved by the NOC or petroleum authority.

It is necessary to incur abandonment costs under normal oil industry practice. They may not be specifically mentioned in the classifications of Exploration Expenditure, Appraisal Expenditures or Development and Production Expenditures in a PSA. Such costs, while not mentioned, would be regarded as Operating Expenses.

Abandonment costs can be substantial, and since they are incurred at the end of commercial production, companies generally have to create reserves or provisions in earlier periods in order to be able to meet them. In some countries, companies have to pay the sums set aside to the government, which then releases the money to meet actual abandonment expenditure when it is incurred.

Environmental Expenses

Environmental clean-up projects generally involve large expenditures. This is particularly so for chemical plants, oil refineries, and any business activity heavily dependent on the use of chemicals or petroleum products. Environmental costs to clean up spills or environmental damage caused by the owner of the land are typically deductible. An expenditure that returns property to the state it was in before the situation prompting the expenditure arose, and that does not make the relevant property more valuable, more useful, or longer-lived, is usually a deductible expense as it is in the nature of a repair. However, expenditures which are to improve land that was acquired and that had environmental damage when acquired will be in the nature of a capital expenditure and should be capitalized to the property. The auditor should verify that these types of expenditures are treated correctly for tax purposes.

There may be an issue regarding the tax deductibility of environmental fines and penalties. Some county's court rulings have held that businesses can deduct fines and penalties levied for violating environmental and other laws. These rulings have characterized such fines or penalties as an operating expense in conducting a business and may be deducted from their business income for tax purposes. Other country's tax code or rulings do not allow fines or penalties to be deducted. As a result, an environmental fine or penalty may be erroneously characterized as an environmental expense and deducted. This issue will depend on whether the country's tax code addresses this and whether the country's courts have established precedent on how this cost should be treated for tax purposes. The deductibility of environmental fines and penalties depends on the facts and circumstances surrounding the nature of the assessment. Generally, a fine which is compensatory, or designed to provide restitution for economic damages, would be deductible as an ordinary business expense. However, if the fine is for punitive purposes or serves a punishment function (e.g. criminal fine), then it may not be considered deductible as an ordinary and necessary business expense.

Bonus Payments

Bonus payments are paid upon execution of the concession or PSA. Such payments are capitalized to the license. When examining the accounting records, the auditor should note how bonus payments are tracked and whether there are any installment payments being made that are in the nature of a bonus amount that has been divided up and made payable over a set number of years. An installment bonus payment structure may be recorded in the accounting records as an annual payment which is expensed. If the annual payments are for a fixed number of years regardless of production and if the license holder is unable to avoid such payments by terminating the license, such annual payments are in the nature of an installment bonus and should be capitalized as part of the cost of the license. Installment bonus payments which are being improperly expensed are generally found in the expense account records for the mineral property or license and the nature of the payments would be determined by examination of the provisions of the license.

Rental Payments

Oil and gas licenses may provide for the payment of rental payments which are based on a monetary unit per square kilometer and paid annually. Such payments will generally decline over time as the license acreage is reduced by relinquishments of portions of the original license acreage. The purpose of the payments of the rental must be examined to determine whether the payments are actually rentals, license bonus, or royalty payments. Delay rentals are not payments for oil or gas to be produced. The payment of delay rentals are preproduction costs which are capitalized to the depletable basis of the property held for development or if development is reasonably likely at some future date.

Geological and Geophysical Expenditures

Geological and Geophysical (G&G) data is often purchased for the purpose of obtaining data that will serve as a basis for the acquisition or retention of a mineral property by a taxpayer engaging in exploring for minerals. These expenditures are typically considered capital in nature and capitalized to a property. They also may be charged to current expenses as the data becomes worthless over time and the tax treatment of these expenditures will depend on a country's tax code. From a PSA perspective, these capitalized costs are typically amortized over some stated period of time (e.g. 5 years, 6 years, etc.) and recovered through the cost oil provisions.

The areas of interest covered by geological and geophysical surveys should be precisely determined. The auditor should obtain copies of the Authority for Expenditure (AFE) pertaining to geophysical projects which are expensed. The auditor will typically examine G&G expenditures which were associated with abandoned or non-productive properties to determine why the properties were abandoned or why there were no properties acquired in the areas covered by the G&G expenses. Properties can be abandoned or not pursued for acquisition based on lack of prospectivity, awarding of a license to another party, or other reasons.

Seismic surveys will often be divided into reconnaissance and detailed surveys. A reconnaissance survey is broader in aerial coverage is used to identify areas of potential interest and prospectivity. Areas which warrant further interest based on favorable geological conditions are then covered by additional surveys. The cost of the reconnaissance-type survey is capitalized and allocated to the areas of interest which are located by this survey. The cost is allocated equally to each area of interest regardless of size or relative cost.

The cost of further exploration (detailed or intensive surveys) is capitalized to the area of interest being surveyed and the costs are allocated to the areas of interest on a proportional basis.

Taxpayers usually designate many "areas of interest" so that a large portion of the geological and geophysical costs are capitalized to areas of interest which are later relinquished or abandoned.

If an entire area of interest proves unfavorable for development (e.g. if no license is obtained or retained for land within or adjacent to the area of interest), the allocated exploration costs (reconnaissance and detailed costs) are deductible as a loss in the year the area is abandoned or relinquished. If only a portion of an area of interest proves worthless, a loss cannot be deducted until the complete area of interest is abandoned as a potential source of mineral production. The auditor should examine any records or maps showing what licenses the taxpayer holds within the project area.

Geological and geophysical expenses may be charged to "Other Professional Expenses." If such an account exists, the charges to it should be analyzed to see if such costs are included there and being expensed when they should be capitalized. Geological and geophysical costs are sometimes erroneously deducted as intangible drilling costs.

Operating Expenses

Operating expenses may be depicted in the accounting records as Lease/License Operating Expenses (LOE) and involve the general costs to operate the well. Such costs include monthly costs for fuel to operate surface facilities at the well site, repairs of well equipment, supplies consumed in operating the well, pulling sucker rods, cleaning the well, rental of equipment, etc.

Professional and Other Expenses

Professional expenses cover various technical, managerial and legal professional expenses. Intangible drilling expenses and geological and geophysical expenses may be erroneously charged to Professional Expenses or Other Expenses categories in the accounting records and tax form.

Other expenses can be comprised of legal, travel or other business expenses. Legal expenses associated with acquisition of production sharing agreements, concessions or other contracts to acquire the rights for oil and gas exploration and production should be capitalized. Expenditures incurred for the acquisition of oil and gas properties or licenses must be capitalized and allocated to the license or property involved.

Royalty Payments

Royalty payments made to the mineral owner (i.e. host country) by the oil company are deducted from gross income and are not subject to income tax.

Intangible Drilling and Development Costs (IDC)

Intangible drilling and development costs (IDC) are all expenditures made for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. For tax purposes, an oil company will make an election to treat intangible drilling and development costs as either a capital expenditure allocated to a property or as an expense which is deducted in whole from the gross income for tax calculations, unless a country's tax code specifically disallows this.

Depreciation

Depreciation is a method to allocate the original cost of an asset to the accounting periods benefited by its use. Various depreciation methods have been developed for tax and financial purposes. Companies can use a different method for each asset or group of assets. Cost recoupment of tangible asset costs is through depreciation. Expenditures to keep an asset in good working order are expensed in the period in which they are incurred. Substantial expenditures to improve the quality of the asset or extend its life are capitalized and recovered by depreciation. Examples of typical oil company equipment that would be depreciated include separators, tanks, pump-jacks, pumps, etc. A useful resource for an auditor, who is unfamiliar with oil and gas equipment, is the Composite Catalog of Oil Field Equipment and Services published by World Oil. This publication is a four volume catalog that describes various types of equipment and services used in the oil and gas industry.

Depreciation methods have three variables in their formulas – (1) cost basis; (2) expected life of the asset; (3) residual or salvage value at end of the asset's life. A country's tax authority may allow a different depreciation method for tax purposes than those typically used for financial reporting purposes. Tax depreciation methods typically involve accelerated recovery of the capitalized costs of the asset. Accelerated methods may use shorter asset life for tax purposes or a greater recovery of costs in the early years and smaller recovery of costs in later years. Examples of depreciation methods include, but are not limited to:

- Straight line
- Declining balance
- Unit of production

Depreciation methods are covered in any basic accounting textbook, so their basic calculation will not be discussed in detail here. However, the Straight Line Method is shown to illustrate the basic concept. The Straight Line (SL) Method assumes a constant depreciation allowance value per year.

SL Annual depreciation allowance = *(Cost of asset – Salvage value at end of life) / (asset's useful life)*

Example SL Method depreciation Calculation

An asset is purchased for $20,000 and has an estimated salvage value at the end of its useful life of $5,000. Its estimated useful life is 5 Years

Annual depreciation = *($20,000 - $5,000) / 5* = $3,000 per year

An audit of depreciation typically focuses on a review of the depreciation schedule and evaluating:

- Whether the depreciation method and calculation is correct
- Whether the asset life is correct
- Whether the salvage value is correct
- Whether the cost basis is correct

An issue that can come up in tax examinations of depreciation is whether an expenditure on the asset is more in the nature of a repair and expensed or whether it is more in the nature of a capital item which extends the asset's life or changes its purpose and should be added to the cost basis of the asset. A company may seek to characterize a capital expenditure as a repair expense in order to reduce taxable income.

Depletion

Depletion of natural resources is the expensing of the portion of the natural resource used up (i.e. extracted or harvested) in a given accounting period. Volumes of oil and gas which have been discovered and considered commercially recoverable, but have not been produced, are referred to as reserves. Oil companies must estimate the volumes which can be recovered based on technical data at the time of the evaluation. As new geological and engineering data is received, the volume of recoverable reserves may change over time.

Oil and gas reserves are typically categorized into proved, probable and possible. Proved reserves are those volumes with a high confidence and reasonable certainty in their recovery based on the geological and engineering data at the time of the determination. Probable reserves are those volumes which have less confidence in being recovered than proved but more confidence than possible reserves. Possible reserves are those volumes with the lowest confidence level for recovery.

The depletion formula is:

Annual depletion allowance = (Adjusted Basis) (Units removed and sold during year) / (Units Recoverable at beginning of year)

The adjusted basis in the formula is:

cost basis – cumulative depletion taken

Example of Depletion Calculation

An oil property has an initial investment (cost basis) of $150,000. Wells have been drilled indicating that recoverable reserves are 1,000,000 barrels of oil and gas. The property is developed and production is started where 50,000 barrels are extracted and sold per year.

Year 1 cost depletion: ($150,000) [(50,000) / (1,000,000)] = $7,500

Year 2 cost depletion: ($150,000 - $7,500) [(50,000) / (1,000,000 - 50,000)] = $7500

Note that in later years (e.g. year 2) the cost basis and remaining reserves recoverable and used in the formula takes into account the basis recovery and reserves produced and removed in prior years (e.g. year 1).

The principle audit issue for depletion is:

- What reserves category should be used in the depletion formula (e.g. proved reserves, proved plus probable reserves)? The amount of recoverable reserves may change as new data is received and the subsurface conditions are better understood. Thus, an oil company may change the amount of reserves it believes are recoverable in a given category. As a result, the amount of ultimate reserves to be recovered (e.g. the denominator in the formula) can change and the auditor will need to review this, evaluate how such adjustments are tracked and shown for depletion purposes and determine if the change is equitable and has a reasonable technical foundation.
- Whether the recoverable reserves used to determine the depletion allowance is correct?
- Whether the cost basis is correct?
- Whether the production extracted in a given year is correct?

Amortization

Amortization is a method of recovering the costs of intangible assets (e.g. patents). The asset is amortized over its useful economic life or legal life established by a tax or petroleum authority, whichever is less. Oil companies may have patents or knowhow which are intangible assets. The straight-line method is typically used to calculate the annual amortization allowance.

The principle audit issue for amortization is:

- Valuation of intangible assets
- Whether the cost basis is correct?
- Whether the asset life used in the calculation is correct?

The tax treatment of Intangible property is often not addressed in the tax code of a country and may be addressed through court rulings or directives issued by the tax authority for a given fact situation. Where the country has not developed court rulings or tax directives issued which provide some legal reasoning covering a specific factual situation, these issues can be difficult to factually develop and determine what the appropriate tax treatment should be. Issues that can come up in tax audits are how to value or determine the tax treatment of:

- Technology used or developed in cooperation with third parties due to a technology license
- Intellectual property rights and their economic decay
- Transfer of trade secrets or know-how to related parties and how that transfer is treated for tax purposes

2.4 Petroleum Tax Issues – Miscellaneous

2.4.1 Transfer pricing - meaning

Transfer pricing is a term used to describe the pricing of transactions between associated (or affiliated – the terms are used here interchangeably) parties, such as companies within the same group, or branches or divisions within the same company. If there is no legislation to prevent it, transactions between associates may be priced differently from arm's length transactions for tax purposes. If one company *sells* goods or services at *less* than an arm's length price to an associated company, this reduces the taxable profits of the first company and increases those of the second company. If a company *buys* goods or services from an associated company at *more* than the arm's length price, this similarly reduces the first company's taxable profits and increases those of the associated company. Where such transactions take place between companies in different countries, this has the effect of transferring taxable profits from one country to another (where tax rates might be lower).

2.4.2 Transfer pricing – importance in petroleum industry

Transfer pricing can be a particularly important issue in the petroleum industry, since transactions between associates are common. Many international oil groups carry out downstream as well as upstream petroleum operations (i.e. they are "vertically integrated"), so it is quite common, for example, for an petroleum producing company to sell petroleum to an associated refining company. It is also common for a petroleum contractor to purchase technical or administrative services from an associated company which exists to provide such services to all the operating companies in the group.

The upstream petroleum industry is normally taxed at a higher rate than other industries in the same country. Manipulation of transfer prices can therefore shift taxable profits from a highly taxed upstream company to a lower-taxed downstream associate. This can result in tax avoidance even where transactions between associates occur <u>within</u> a country, as well as where they cross national borders.

There are some commercial constraints on manipulation of transfer prices by oil companies:

- Some oil companies are not vertically integrated. This makes sales of petroleum to associates less likely. But companies could still sell petroleum to <u>trading</u> affiliates even if not vertically integrated.
- International oil companies often require their group companies to trade with each other as if they were independent profit-making centers. Thus a refining company in an international oil group may be required to maximize its profits by purchasing oil as cheaply as possible wherever it can, with the result that it will not purchase oil from an associate at more than the normal market price. (But if major tax advantages could be obtained by trading on non-arm's length terms it is possible that this requirement might be ignored in practice.)
- Joint venture arrangements provide a commercial constraint on transfer pricing abuse in relation to costs. If a field operator pays more than the market price for goods and services purchased from an associate, this reduces the profits of its joint venture partners, who will naturally take steps to ensure that this does not happen.

Transfer pricing abuse thus remains a potential risk. It is important to be aware of the risk of abuse and ensure that the available countermeasures are properly applied if necessary.

2.4.3 Transfer pricing – OECD guidelines

The OECD has published general guidelines on transfer pricing and the use of the arm's length principle, which form the basis of the approach taken by most tax jurisdictions to this topic. Since these are of general relevance they are not considered in this specialist manual, but familiarity with them is useful. They are not published for free on the internet, but a summary can be found at http://en.wikipedia.org/wiki/Transfer_pricing.

2.4.4 Transfer pricing – special rules for contractors

The auditor should review the country's PSAs and Income Tax Act to determine whether they contain any special transfer pricing rules for petroleum. The arm's length principle plays an important part in those rules, subject to certain exceptions.

Note that a PSA may require contractors to carry out all transactions giving rise to revenues, costs or expenses on an arm's length basis, unless otherwise agreed in writing between the company and the government. The auditor should determine whether any special petroleum valuation provisions are in the PSA and whether the Income Tax Act requires contractors to disclose all non-arm's length transactions.

The rules applying to contractors may be much wider than the general income tax rules on transactions between associates. The auditor should determine whether a country's tax code may require companies to report all such transactions at arm's length prices for tax purposes or it may permit the country's Tax Commissioner to adjust income or re-characterise transactions in such cases.

As indicated above, the arm's length pricing requirement is subject to specific exceptions:

- It does not apply where there is a written agreement to the contrary between the company and the government. (Conceivably this could happen, for example, if the government negotiated a special price for sales of oil or gas into the local market.)
- It is overridden by the special valuation rules for oil, which may require average market prices to be used for all tax purposes.
- There are a number of special rules for costs paid to associates in respect of services, materials, legal services, and insurance. The aim of these specific rules is to limit costs paid to associates, and they generally do so by requiring arm's length pricing, but in some cases they could be argued to depart from normal arm's length pricing. For example, the formulae for pricing of materials may in some instances not exactly reflect the market value of those materials. And a company operating at arm's length would not normally provide services to another company at cost as is required for services provided by affiliates. These should be taken as further examples of the arm's length pricing requirement being overridden by written agreement.

2.4.5 Transfer pricing – identifying non-arm's length transactions

A country's tax code may provide that contractors are required to disclose all non-arm's length transactions. The auditor should review the tax code and determine if this is a requirement.

Although non-arm's length transactions have so far been discussed solely in terms of transactions between associates, it should be borne in mind that transactions can be on non-arm's length terms for other reasons. For example, the pricing of a transaction between non-associated companies could be influenced by the pricing of a separate transaction between the same or linked companies. This would not be a genuine arm's length transaction. Or a company could be forced by government regulation to sell petroleum to a particular purchaser at a particular price – again not a genuine arm's length transaction. Transactions such as these are subject to the disclosure requirement.

In any case where a transaction clearly does not reflect the true market price but has not been disclosed by the company as non-arm's length, it is important to establish the circumstances of the transaction. You should not accept unquestioningly that because it is between non-associated parties it must be on arm's length terms.

2.4.6 Currency gains and losses

The PSA may require oil companies to keep accounts in US dollars and the country's local currency. In the case of conflict, the PSA may stipulate the accounts maintained in US dollars will prevail.

The US dollar is the currency normally used in the oil industry for pricing of oil and international contracts for goods and services. Dollar accounting, which is standard for oil companies, therefore minimises the occurrence of exchange gains and losses in their accounts, though these may still arise, particularly where oil companies source goods and services locally in the host country. Exchange differences on such transactions should be taken into account for the purposes of calculating profit petroleum and income tax on petroleum operations, so long as they relate to allowable contract expenditure.

A PSA or its annex may contain a general statement that it is the intent of the accounting and financial procedure that neither the government nor licensee should experience an exchange gain or loss at the expense of, or to the benefit of, the other. If a company reports substantial or abnormal exchange losses, you should consider not only whether they genuinely relate to allowable contract expenditure but also whether they are consistent with this stated intention.

The auditor should determine whether the PSA has provisions which specify the exchange rate to be used for the purpose of conversion of currencies. Similar provisions may also be incorporated in the country's Petroleum or Income Tax Act.

2.4.7 Hedging

Companies may take steps to hedge against movements in the price of petroleum. International companies often carry out such hedging operations through their head office management company, since it has a complete picture of group companies' overall net exposure to risks, and can hedge them more efficiently. But sometimes local companies may be allowed to hedge their own risks, perhaps because it is considered more tax efficient.

There are many types of hedging instrument, but in general they are based either on a forward contract (which obliges both parties to deal at a future date at a set price) or an option (which gives one party the right to deal with the other at a future date at a set price). Instruments of the latter type raise more complex accounting issues. For simplicity, the following paragraphs consider the issue of hedging by reference to the former type of instrument.

A forward contract can be settled physically – for example a company could agree on 1 January of year 1 to deliver x barrels of oil at $y per barrel on 1 January of year 2, and physically deliver that oil on the due date. Alternatively, and more commonly, a company expecting to produce x barrels of oil on 1 January of year 2 could enter a separate cash-settled forward contract to sell x barrels at $y per barrel, under which it would receive or pay cash representing the difference between the forward contract price and the actual price on the date of settlement. The net economic effect of these transactions is similar.

The auditor should determine whether there are any specific rules in the PSAs or income tax legislation on hedging transactions in respect to petroleum prices.

If petroleum is physically delivered under a forward contract at a price less than the normal market price that would have prevailed for a spot transaction, a potential audit issue may arise. The issue is whether it should be regarded as a discount sale under any valuation rules in the PSA and whether the price realised should be disregarded for the purpose of calculating the average market price and profit oil calculations.

Losses on cash-settled hedging transactions should be considered non-recoverable for the purpose of calculating royalty and profit petroleum on the grounds that they do not relate directly to petroleum operations, and do not meet the "appropriate and necessary" test for recoverability. Conversely gains on cash-settled contracts should not be taken into account for the purposes of calculating royalty or profit petroleum.

As far as income tax is concerned, petroleum produced should be valued on the same basis as for royalty and profit petroleum where petroleum is physically delivered under a forward contract, i.e. as explained in the paragraph above. In the case of cash-settled contracts, losses may not be accepted as contract expenses under the PSA profit oil and cost oil calculations and thus may not be set against petroleum gross income. Note that gains or losses on these instruments are likely, however, to be taxable or deductible under normal income tax rules, i.e. gains taxable as non-petroleum income and losses deductible against non-petroleum income – if there is sufficient non-petroleum income to absorb the losses.

It is possible that the effect of the above rules will be that companies hedging against petroleum price movements are taxed when the transactions are profitable, but find it difficult in practice to obtain relief for any losses suffered. In practice therefore companies may be reluctant to carry out such hedging transactions within a country.

In the case of gas, the treatment of forward contracts will depend on the precise valuation terms agreed with the government.

The following examples therefore relate to oil, not gas.

Examples

a) A company expects to lift 500k barrels of oil in 6 months' time. The current oil price is $100 per barrel, but the company expects the price to fall, and enters a futures contract to hedge against that expected fall. In fact, however, the oil price after 6 months is $125, and the company incurs a loss of $12.5m on settlement of its futures contract. The value for tax purposes of the 500k barrels sold is $62.5m but the company claims a tax deduction for its $12.5m loss.

The loss is not recoverable for production sharing or royalty purposes. It can be deducted for income tax purposes, but not against contract revenues under the ring-fence principle.

b) Same facts as above but the price of oil at the end of 6 months is $75 per barrel, so the company makes a $12.5m profit on its futures contract. The profit would be disregarded for production sharing but should be included in income tax profits (though not as petroleum income).

c) A company expects to lift 500k barrels of oil in 6 months' time. The current oil price is $100 per barrel, but the company expects the price to fall, so, to hedge against such a fall, it enters a forward contract with a non-affiliated purchaser to sell 500k barrels to that purchaser in 6 months' time for $50m. At the end of the 6 months the company produces 500k barrels with a market value of $62.5m, but sells them to the purchaser for $50m under the terms of the agreement. The company argues that this is an arm's length transaction in a freely convertible currency and that the realized price of $100 per barrel should therefore be used for the purpose of calculating the market price under the PSA.
The $100 price is a discount price in relation to the value of the oil when it is produced, and there was no necessity for the company to enter a transaction to sell the oil at that price. However it may have been a prudent action which is consistent with reasonable standards of business practices. The issue is whether it should be disregarded in calculating the market price for the purposes of royalty, profit oil and income tax.

d) Same facts as in c) but the price of oil at the end of 6 months is $75 per barrel, so the company sells oil with a market value of $37.7m for $50m. The company argues that the $100 per barrel price realized should be disregarded for the purpose of calculating the market price. If the transaction was entered into on arm's length terms there is nothing in the valuation rules that requires it to be ignored for the purposes of determining the market price.

2.4.8 Transfer of license interest – reasons for transfers

There are many commercial reasons why a company might decide to dispose of or transfer some or all of its interest in a petroleum license. The following are just some examples:

- A company might change its views on exploration and production prospects, either in the country generally or in a particular license area, or it may change its views on the future market and prices for a country's oil type and grade.
- It might change its priorities and decide, for example, to concentrate more on production than on exploration and appraisal.
- It might consider itself to have particular expertise in certain kinds of petroleum operation. If its expertise is in exploration and appraisal, it might choose to dispose of its interest when the exploration stage is completed, so that it can use its resources on exploration elsewhere; if its expertise is in development and production, it might wish to acquire a license area for development following successful exploration by another company.
- Smaller companies might find themselves with insufficient resources, or be unable to raise enough finance, to carry out development operations (which may be more expensive or difficult than anticipated). Even if they can afford these higher costs, they might still prefer to spread their risks. Or they might wish to avail themselves of the greater experience and expertise that a larger company could bring to a major and challenging development project.

- When oil companies merge, there might be a change of policy, or a need to rebalance their joint asset portfolio. Or a single company might just wish to simplify and rationalize its holdings.

Taxation may sometimes be a factor affecting a company's decision to sell a license interest, but as these examples demonstrate, there may also be valid commercial reasons, and these may mean that the government in turn benefits from the transfer.

2.4.9 Transfer of license interest – rights under agreements

The JOA will normally permit the transfer of an interest, and set out the rules to be followed. It is common for other joint venture partners to have pre-emption rights – that is, the right to acquire the interest being sold at whatever price the assignor is proposing to accept from a non-JV partner.

PSA's also contain detailed provisions relating to such transfers. The PSA may require government consent to be obtained, such consent not to be unreasonably withheld. Where the transfer is to an affiliated company the transferor remains bound by the terms of the PSA. Where it is to a non-affiliated company, the transferor must obtain a written undertaking from the transferee to abide by the terms of the PSA, including payment of any performance bond. The PSA gives the government no preemption rights.

Where a license interest is transferred the transferee becomes subject to the terms of the PSA (and should therefore be regarded as being a licensee or contractor for the purposes of the PSA and Income Tax Act respectively.

Where one JV contractor company commits a material breach of a non-joint obligation under a PSA, the government has the right to terminate its equity interest and share it among the other JV partners in proportion to their interests.

2.4.10 Transfer of license interest – types of transfer

If an IOC wishes to end or reduce its operations in a country, it typically has two choices:

- It can sell its shares in its subsidiary set up in the country, or a proportion of them, to another company;
- Alternatively the subsidiary can transfer its license interest, or part of it, to another company.

Where the second option is taken, there are various types of consideration that a company might receive:

- <u>Cash</u> payment. This is the most common and straightforward method.
- An interest in another license offered in exchange, in the country or elsewhere (a <u>swap</u>).
- An agreement by the transferee to meet an agreed proportion of the transferor's cost obligations for a future period. The term often used for this in the oil industry is a <u>farm-out</u> (considered from the transferor's perspective) or farm-in (considered from the transferee's perspective). A variant is that the transfer of the interest is to occur <u>after</u> the transferee has met an agreed proportion of the transferor's cost obligations. The term sometimes used for this in the oil industry is an <u>earn-out</u> (or earn-in.)

These different kinds of transfer can be combined. For example, a company could transfer its interest in exchange for an interest in another concession or production sharing agreement plus some cash payment. Or it could transfer its interest in exchange for cash payment plus an agreement to meet a proportion of its future costs.

There are possible commercial reasons for companies entering into swaps, farm-outs or earn-outs rather than just selling their interest for cash. For example these arrangements may make it more difficult for JV partners to disturb a negotiated deal by exercising their pre-emption rights.

2.4.11 Transfer of license interest – tax issues

When an interest in a license is transferred there are two main tax issues to consider:

1. How the consideration is to be treated for tax purposes; and
2. How costs are to be allocated between the transferor and the transferee.

On the first point, consideration received for a license transfer may not form contract revenue under the terms of a PSA, and it is not subject to royalty. For income tax purposes, a country's Income Tax Act may provide that no gain or loss is to be taken into account in determining the income of the transferor. The auditor should review the country's tax code and regulations to determine whether it provides that the transferee's cost base for an asset transferred is the same as the transferor's immediately before the disposal, so the consideration is ignored in determining the transferee's income too.

The rule that no gain or loss is to be taken into account applies both where a licensee transfers its license interest, and where a parent company sells an interest in a subsidiary in the country that holds a license. It applies to swaps, farm-ins and earn-ins in the same way as to cash disposals. Where a transferee meets a transferor's obligations under a farm-in or earn-in, the amount paid by the transferee under this arrangement should just be ignored in determining each party's income.

On the second point, the allocation of cost presents an issue only in the case of costs that are to be depreciated. (In other cases costs are clearly attributable to the party who incurred them.) An auditor should review the country's tax code to determine whether it provides that the transferee continues to depreciate or amortize the asset in the same way as if the transfer had not occurred.

This leaves open the question of how exactly the annual depreciation of an asset should be allocated between the transferor and transferee for the year in which a license transfer occurs. In the case of costs incurred <u>after</u> the date of the transfer it is clearly appropriate that the annual depreciation should be wholly attributed to the transferee. In the case of costs incurred <u>before</u> the transfer, the choice is between attributing the annual depreciation wholly to the transferor, or apportioning it between the transferor and the transferee on a time basis. In practice it may be attributed wholly to the transferor. However if the transferor and the transferee both <u>agree</u> that it should instead be apportioned on a time basis, this can be accepted. For tax purposes the only essential point is that between them the transferor and transferee should deduct the depreciation for the year only once.

Example

Company A has a 25% interest in a license. It transfers this interest to company B on 31 March. Costs attributable to this interest in the year are as follows:

	1 Jan – 31 Mar	1 Apr – 31 Dec
Development costs*	$9m	$12m
Operating costs	$3m	$9m

*All depreciable on straight line basis over 6 years

Company A's deductible costs for the period from 1 January to 31 March are therefore

Development costs \$9m x 1/6 =	\$1.5m
Operating costs	\$3m
Total	\$4.5m

Company B's deductible costs for the period from 1 April to 31 December are

Development costs \$12m x 1/6 =	\$2m
Operating costs	\$9m
Total	\$11m

Over the following five years Company B can deduct the remaining \$17.5m depreciation of the total \$21m development costs until the costs are fully depreciated.

If, in the above example, the companies agreed to time apportion the depreciation of the \$1.5m development costs incurred before 31 March, then A's deductible costs for the period 1 January to 31 March would be reduced by \$1.125m and B's deductible costs for the period 1 April to 31 December correspondingly increased by \$1.125m.

Taxation of gain on transfer of a license interest

A capital gain on transfer of a license interest is chargeable to income tax, and is treated as income arising from petroleum operations. It is disregarded for the purpose of calculating royalty or profit petroleum.

The cost of acquiring a license interest is deductible in calculating income tax from the contract area. The deductible cost is equivalent to the assessed gain. However these costs typically are not recoverable in calculating profit petroleum.

Calculation of taxable gain involving transfers

In calculating the gain on transfer of a license interest, the cost base must exclude:

- Non-deductible costs, or
- Costs that have already been deducted.

Costs already deducted for tax purposes by the transferor for tax purposes cannot be deducted in calculating the gain. This follows from the principle that no cost can be deducted twice.

The taxable gain is calculated as:

- The consideration received for the assignment of the interest
- Less allowable costs incurred by the transferor but not yet deducted.

Allowable costs not yet deducted are made up of two elements: costs not yet depreciated and excess costs.

Costs not yet deducted

Broadly speaking, development costs are generally depreciated over some period of time pursuant to the Income Tax Act for tax purposes. The cost of capital assets, less the depreciation already allowed, is often called the tax Written Down Value (WDV). The WDV at the date of transfer represents costs incurred by the transferor for which a deduction has not been allowed, and these can be deducted in calculating the transferor's capital gain.

Excess costs

The excess of the deductible costs for a year (including excess costs brought forward) over that year's gross income is carried forward and deducted against profits of later years, subject to any provisions in the tax code. To the extent that these excess costs are still available to carry forward at the date of transfer of a license interest, they are again costs for which the transferor has not had a deduction that can be deducted in calculating the transferor's taxable gain.

So long as only these transferred costs – i.e. the tax WDV of capital assets and the excess costs carried forward at the date of the transfer – are deducted for the purpose of calculating the capital gain, non-deductible costs and costs already deducted will automatically be excluded from the calculation.

Example

> On 1 January company A transfers its interest in a license area to company B for \$100m. At that date, the transferred costs incurred by company A but not yet deducted are \$35m – comprised of the tax WDV of development costs amounting to \$25m, and excess costs carried forward amounting to \$10m. The capital gain to be taxed on the transferor is therefore \$100m - \$35m = \$65m. It should be treated as income from the contract area concerned.

Tax treatment of sum paid for transfer of license interest

The tax treatment of the sum paid by the transferee can be illustrated by the previous example. The transferee, company B, can treat the \$65m cost of the goodwill as a deductible cost to be depreciated over the number of years allowed under the tax code, against gross income from the contract area. The transferee cannot deduct the remaining \$35m paid for the assignment under this provision, but will be able under the normal rules to depreciate the transferred tax WDV of \$25m and deduct the excess costs of \$10m in calculating income from the contract area, subject to any cost recovery limits under the tax code.

Note that the transferee is entitled to the \$65m deduction only if the corresponding gain has been taxed on the transferor and tax on it has been paid. Before allowing a deduction it is important therefore to check that the transferor has both declared the capital gain <u>and</u> paid tax on it.

Transfers for non-cash consideration

Where a license interest is transferred for a consideration other than cash (for example in a swap or a farm-in), the calculation of the gain must be based on the market value of the non-cash consideration received. The companies concerned must provide a detailed justification of the value they propose to use for this purpose. This could be a very complex and uncertain exercise, and this manual does not discuss the methods that might be used. An essential requirement is that the same value should be used for both transferor and transferee. If the same value is agreed by both parties, then in practice, so long as it appears broadly reasonable in the light of the justification provided, it should be accepted. Any minor inaccuracy in the valuation should have no major fiscal impact in view of the fact that the tax treatment of both parties is broadly symmetrical. If, however, the transferor and transferee do not agree the same value, it will be necessary to determine the appropriate value. In material cases it may be necessary to require the companies concerned to seek third party arbitration on the issue.

Transactions involving farm-ins, swaps and the like can be very complex and the tax treatment will depend on the facts and circumstances of the transaction.

Transfer of part of an interest

A company might transfer only a part of its licence interest. Normally the transfer agreement will specify the percentage interest acquired by the assignee, and it will thus be simple to calculate what proportion of the transferor's interest has been assigned. The rules described above can then be applied on the basis of that proportion.

Example

The facts are as in the previous example, but the interest assigned is only 40% of company A's interest. The tax WDV and excess costs to be deducted must be restricted to that percentage. The gain of the transferor is therefore \$100m - \$21m = \$79m. The transferee company B can depreciate the \$79m as allowable capital expenditure. It will also be able in due course to depreciate the transferred WDV of \$15m and deduct the excess costs of \$6m relating to the acquired interest.

Transfers between affiliates

When a contractor transfers all or part of a licence interest to an affiliated company, the affiliated companies are then held jointly and severally liable for meeting the obligations imposed by the agreement. This may be regarded as a disposal for the purpose of tax on capital gains. Note that some countries allow a company to form entities which are part of a consolidated group within that country and transfers of interests between entities which are part of a consolidated group may not be considered taxable events, depending on the circumstances and facts.

Transfer of an interest for less than the value of its assets

A company may assign an interest in a concession or production sharing contract for less than the value of the transferred costs. This may happen if, for example, most of an exploration programme had been completed and the results indicated the area's prospectivity was low but there were still some small potential that oil would be found.

Taxation of gain made by the transferee

In the above circumstances, a loss accrues to the transferor and a gain to the transferee. The gain of the transferee is treated as income from the contract area for tax purposes, arising in the year(s) when the transferred costs are deducted, in proportion to the costs deducted in each year.

Example

> Company A transfers a licence interest to company B for $50m. The tax WDV of its development expenditure at the date of transfer is $30m and its excess costs are $40m. As explained in previous examples, company B will in due course be able to depreciate the $30m development costs and deduct the $40m excess costs, subject to cost recovery limits. Since it has paid only $50m but has acquired the right to deduct $70m costs in future, it has effectively made a gain of $20m, which is taxable. The gain is not taxed in full in the year when the transfer occurs, but is taxed in the years when the costs are deducted, in proportion to the costs deducted. In effect, when B claims deductions for the transferred costs, they are restricted by 20/70ths.

Again this gain does not in any way affect the calculation of profit petroleum.

Deductibility of loss made by the transferor

In the foregoing example the transferor has made a capital loss. This can in theory be deducted against income from the contract area, but where a transferor company has disposed of its entire interest in a licence and has excess costs, then by definition it has no income from the contract area for the current year against which it can set this loss, nor will it have any income in future years since it has sold its entire licence interest. But in other circumstances the transferor might be able to utilise the loss, for example where the loss relates not to excess costs but to capital expenditure not yet allowed, or where the contractor has a continuing interest in the licence.

Sale of shares in a contractor

Instead of the contractor selling some or all of its license interest, the owner of the shares in the contractor (i.e. the parent company) may sell some or all of its shares in the contractor company. The parent company may make a gain (or loss) on disposal of the shares reflecting the increase (or decrease) in the value of the license interest owned by the contractor. The taxability of such a gain depends on the application of normal income tax law.

Tax on capital gains applies under to all gains on the disposal of business assets in the business income of a taxpayer. Typically a "Business asset" is defined broadly under a country's tax code to mean an asset used or held ready for use in a business and expressly includes any asset of a company. Thus, the shares held by the parent company are a business asset for the purposes of the country's Income Tax Act (ITA).

As a non-resident company, the parent company is typically subject to a country's tax obligation only on source income from that country. An auditor should review the tax code to determine whether there is a list of income that is treated as source income and set out in the country's tax code. An auditor should determine whether the country's tax code explicitly treats a gain on the disposal of shares in a country-resident company as country-source income. An auditor should determine whether the country's tax code treats any gain derived on disposal of a share in a company the property of which consists, directly or indirectly, principally of an interest or interests in immovable property in the country as country-source income. The auditor should determine if there is any section of the ITA where a tax treaty applies. The auditor should review the tax code and determine the tax treatment regarding gains from transfer of property and the kinds of property that it applies to. "Immovable property" would have its ordinary legal meaning for this purpose and, therefore, would include the right to take resources from the land, such as the right to take petroleum under a petroleum agreement. Consequently, if the property of the contractor consists principally of an interest in one or more petroleum agreement(s) from the host country, it can be argued that any gain on disposal of the shares in the contractor is country-source income. Further, by virtue of the words "directly or indirectly", the same would apply if the non-resident parent company held the shares through one or more interposed non-resident entities.

A country's tax code, tax treaties and double tax agreements may restrict the right to tax the gain on disposal of shares in a company whose assets consist of immovable property. For example, a tax code or treaty may allow a country to tax the gains on the disposal of immovable property but not to tax the gain on disposal of shares of a company whose principal assets are immovable property. In practice, however, the parent company may be resident for tax purposes in a country which has no double tax agreement or tax treaties.

It may therefore be possible to tax the gain where it takes the form of a disposal of shares in the contractor rather than a disposal by the contractor of its license interest. The main difficulties may be practical. Firstly there is the difficulty of finding out that the sale of shares by the parent company has (directly or indirectly) taken place. It is important therefore to stay abreast of reported developments affecting those companies. Secondly there is the difficulty of recovering tax from a company who is not resident in the country.

The sale of shares in a contractor does not normally have any tax implications for the contractor itself. The contractor continues to own some or all of the assets under the operating agreement, and continues to depreciate them. However, a country's tax code may provide that if there is a change of 50 percent or more in the underlying ownership of a company, then the company is not permitted to carry forward any accrued tax losses unless it is carrying on the same business both before and after the change in ownership, but in the normal case this "same business" test would probably be satisfied

2.4.13 Unitization agreements and re-determinations

Where an oil or gas field straddles two or more contract areas in which different companies have interests, it makes more sense commercially and technically for it to be developed under a single development plan by a single operator rather than as separate developments under separate operators. In these cases the licensees for both contract areas normally enter a Unitisation Agreement, under which the field is developed by a single operator under a jointly agreed development plan, with petroleum revenues and costs allocated between the licensees proportionately to the reserves in each area. (The government can require unitised development in these cases.) As the field is developed there are normally periodic re-assessments of the reserves in each, resulting in re-determinations of the allocations between the licensees. Cash adjustments may be made between the parties in respect of earlier periods to give effect to the revised allocations. However, such retroactive adjustments and reallocations may be restricted or limited in how often they may be made and conditions for any retroactive cash settlement. Any reallocations will be made pursuant to the terms of the unit agreement or unit operating agreement provisions.

The application of tax law to a unitisation agreement will depend on the exact nature of the agreement, but in general terms neither the unitisation nor any subsequent re-determination should be regarded as a disposal of a licence interest. A re-determination should be regarded as reflecting the share the parties had in the development revenues and costs from the outset, the share specified in the original agreement being merely provisional.

As with any other development, it is important to ensure that the costs allocated to a unitised development are appropriate. But so long as they are, the allocation of those expenses to the different licence holders under the terms of the unitisation agreement can normally be accepted for tax purposes.

If a re-determination takes place then strictly speaking the tax calculations of the licensees of the different contract areas should be adjusted for earlier periods to reflect the revised allocation of revenues and costs between them. This can be a complex exercise, and the licensees may propose that for simplicity the re-determination should be ignored for tax purposes, since the adjustments to the parties' tax liabilities will be largely self-cancelling and have no net effect on government revenues. This should only be accepted if:

- It is agreed by all licensees affected;
- The contract area to which a higher share of oil or gas reserves is attributed does not pay tax at a significantly higher rate than the other contract area.

In any case where a re-determination relates to a unitised development spanning national borders, the tax calculation for earlier periods may have to be adjusted.

2.4.14 Sourcing of income and payments to sub-contractors

Generally, a corporation must have a permanent establishment in a country imposing a tax obligation before the corporation is subject to income taxes in that country. A permanent establishment typically involves a corporation having a fixed place of business in the country imposing a tax obligation. A secondary problem is what constitutes taxable income in that country. For example, does a company or individual incur a tax obligation on income earned while they are passing through a country even though they do not maintain a fixed place of business there and do not ordinarily conduct business in that country? Does a company owe income taxes on amounts they receive in a country even though the payments were for services performed outside that country? Such matters may be resolved through tax treaties between countries. However, where such treaties do not exist, the tax treatment on activities conducted within a country may not be well defined and thus subject to legal interpretation of the facts and circumstances of the income, how it was generated and whether it is subject to taxation within one country or another. The tax issue that typically evolves is:

- Whether the company has a fixed place of business in the taxing country
- What constitutes a fixed place of business
- Whether the company earned income associated with activities in the country and whether that imposes a tax obligation

A sub-contractor working for an oil company may be subject to a tax obligation if the income is determined to be sourced within the country or meets certain requirements specified in a country's tax code. The problem that typically occurs is determining whether the sub-contractor earned income that is subject to a country's tax code if the sub-contractor does not have a permanent establishment in that country. A secondary problem can arise when the sub-contractor performs work in a country but is not paid in that country. The sub-contractor may be paid in Country A for work performed in

Country B. Major oil companies may, as a course of business, collect and pay withholding taxes for sub-contractors they use. The auditor should inquire as to what the company's accounting policy is concerning withholding taxes for any sub-contractors used.

PART 3 PETROLEUM TRANSACTIONS

3.1 Types of Transactions

Petroleum transactions can be structured in a variety of ways and are commonly used in the oil and gas business. The auditor should become familiar with the various types of contracts and deal structures used in the industry. A typical transaction used in the oil and gas industry is where a party drills a well on an oil and gas property covered by a license held by one or more party(s) in return for an interest in the license. Farm-outs and Farm-ins are typical "Drill to Earn" deals and can be structured in a variety of ways. Often these deals involve one party who is "Carried" during the drilling of the well since that party does not incur any costs for the drilling of the well. Examples include:

- Drilling a well to earn "X" interest in a license
- Drilling a well to earn "X" interest in the drill site only
- Drilling a well to earn "X" interest in the drill site and "Y" interest in the surrounding or remaining property covered by the license
- Drilling a well to earn "X" interest in the drill site and various interests in selected areas of the remaining property covered by the license

The tax treatment to be afforded to the carrying party and the carried party will differ. Generally, the party who drilled or caused the well to be drilled will be entitled to deduct 100 percent of the Intangible Drilling and development Costs (IDC) if the arrangement is a true carried interest. These types of deals can be structured such that the party drilling the well recoups their drilling investment through payout.

It is a common practice for one party to acquire part or all of their interest in a drilling venture in return for services. In general, a transaction where an interest in a drilling venture is received in return for capital and services furnished by the recipient is not a taxable event . This is due to a general oil and gas tax law concept that has evolved in various countries known as the "pool of capital" doctrine. The same reasoning has been extended to geologists, petroleum engineers, landmen, commercial negotiators, accountants and lawyers who receive an interest in an oil or gas drilling venture in return for services rendered. The "pool of capital doctrine" is widely accepted and used to justify the tax-free receipt of property for services. However, a country's tax code may specifically limit this application to specific circumstances or provide that the receipt of property as payment for services rendered is taxable income to the extent of the fair market value of property received. Generally, for the pool of capital doctrine to apply, all of the following must occur:

- The contributor of services must receive a share of production, and the share of production is marked by an assignment of an economic interest in return for the contribution of services
- The contribution must perform a function necessary to bring the property into production or augment the pool of capital already invested in the oil and gas in place

- The contribution must be specific to the property in which the economic interest is earned
- The contribution must be definite and determinable
- The contributor must look only to the economic interest for the possibility of profit.

Farm-outs and Farm-ins

The use of the terms "farm-in" and "farm-out" involve the transfer of property in a "sharing arrangement." A "farm-out" and "farm-in" occurs when an interest in an oil and gas property, along with the burden of developing the property, is transferred from one working interest owner to another and the transferee agrees to assume the development burden in return for the working interest in the property. The transferor will usually retain some type of interest in the property, normally an overriding royalty interest. A farm-out by *Taxpayer A*, the transferor, is a farm-in to *Taxpayer B*, the transferee. The acquisition or disposition of the interest in property by a farm-in or farm-out will not normally result in a taxable event. The arrangements and details regarding the transfer of any property should be reviewed in detail to ascertain the taxability of the transaction.

Carried Interests

The term "carried interest" generally refers to an arrangement where one co-owner of an operating interest (the "carrying party") incurs an obligation to pay all of the cost to develop and operate a mineral property, in exchange for a right to recoup this investment out of the proceeds from the first production from the property. When the investment amount is recouped it is referred to as "payout". After the investment has been recouped, any subsequent production is split between the co-owners. The co-owner(s) not obligated to pay for the development and operation hold a carried interest in the mineral property until the carrying party's initial investment is repaid.

A typical carried interest arrangement is as follows:

Example:
Taxpayer A owns 100-percent of the working interest in an oil and gas license and is interested in having a well drilled on it. *Taxpayer A* assigns to *Taxpayer B* the entire working interest in the property, and *Taxpayer B* agrees to drill, complete, and equip a well free of all cost to *Taxpayer A*. *Taxpayer B* is to retain 100 percent of the working interest until he/she has recovered the entire cost (drilling, completing, equipping, and operating the well) out of the production from the property. After *Taxpayer B* recovers his/her cost, 50 percent of the working interest in the property is to be transferred back to *Taxpayer A*, and the working interest ownership is to be owned equally by each thereafter. *Taxpayer A* would realize no taxable event because of the transfer. *Taxpayer A* would have no basis in the depreciable equipment and, therefore, would have no depreciation deduction allowance on the value of the equipment acquired by Taxpayer B. Since *Taxpayer B* owns all the working interest and operating rights to the property during the drilling of the well and is entitled to all the income from the entire working interest during the complete payout period of the well, *Taxpayer B* is entitled to deduct all of the Intangible Drilling Costs (IDC) of drilling the well. *Taxpayer B* is required to

capitalize all equipment cost for equipment purchases. *Taxpayer B* will report all income and expenses from the property during the entire payout period. After payout, *Taxpayer B* must capitalize to *Taxpayer B's* basis in the interest acquired the unrecovered equipment cost attributable to the half interest which reverts to *Taxpayer A*.

The examination of *Taxpayers A* and *B* above should include an inspection of the license agreement, carried interest agreement (e.g. farm-out, joint venture agreement, etc), operating agreement, and the accounting records for the costs subject to the carried interest payout. The examiner should make sure that *Taxpayer B* has the full working interest in the license during the complete payout period before allowing *Taxpayer B* to deduct the entire IDC. *Taxpayer B* must also report all the income and expenses from the property. Normally, both *Taxpayer A* and *B* will "monitor" the profits from the property during the payout period.

Another type of carried interest arrangement that is different from the above and has a different tax treatment is where one party is subject to a specific monetary amount recovery limit for payout.

Example:
Taxpayer A owns 100 percent of the working interest in an oil and gas license and is interested in having a well drilled on the property. *Taxpayer A* assigns to *Taxpayer B* the full working interest in the property and *Taxpayer B* agrees to drill, complete, and equip a well on the property free of all cost to *Taxpayer A*. *Taxpayer B* is to retain the full working interest until *Taxpayer B* has recovered $400,000 out of the net profits from the property. At recovery, 50 percent of the working interest in the property reverts back to *Taxpayer A*. *Taxpayer B* knows that it will cost $500,000 to drill and complete the well and another $100,000 to equip the well. In order for *Taxpayer B* to be entitled to deduct all the IDC, *Taxpayer B* must own the entire working interest or operating rights in the well during both the drilling period and the payout period. Since *Taxpayer B* will not own the entire operating rights during the entire payout period, *Taxpayer B* is not entitled to deduct all the IDC. *Taxpayer B* must capitalize to the mineral property basis the IDC and depreciable equipment cost applicable to *Taxpayer A*. *Taxpayer B* must capitalize $250,000 ($500,000 x 50%) of the IDC and $50,000 ($100,000 x 50%) of the equipment cost to their mineral property basis. *Taxpayer B* must also report all the income and expenses from the property during the $400,000 payout period. *Taxpayer A* has no taxable event because of the transfer.

Carried interest arrangements can be structured in a variety of ways and are commonly used in the oil and gas business. The auditor should become familiar with the various types of contracts used in the industry, their provisions and deal structures.

3.2 Economic Interests

A key concept in oil and gas tax principles is "economic interests". An economic interest is any interest in the minerals in place where recovery of the investment is through production of those minerals. Examples of economic interests include working interests, royalty interests, over-riding royalty interests, and production payments. The type of economic interest one has will determine the tax treatment of any expenses associated with that interest. As an example, the holder of a working interest can claim deductions for drilling costs but the owner of a royalty interest cannot claim those same deductions since a royalty interest does not bear any costs to drill and equip a well. In general, tax deductions for drilling expenditures (e.g. IDC) are limited to those holding operating rights (e.g. working interest) since those rights bear such costs while non-operating rights (e.g. royalty) do not bear such costs. Note that non-operating rights is different from non-operators. A non-operator is the party who is not an operator, but their economic interest may still be a working interest which is an operating right. The petroleum industry typically refers to operating interests as working interests.

Operating Interest

An operating interest involves an interest or contractual obligation created out of the oil and gas license authorizing the holder to enter the lands to conduct exploration, drilling, development, production and related operations. Rights originating from an Operating Interest may or may not be transferred through an operating agreement, however, transfer of operating rights generally requires approval from the regulatory agency overseeing the oil and gas industry. The National Oil Company of a country may function as a regulatory agency and their approval may be required before the transfer is recognized in that country. This type of interest is commonly referred to within the industry as a "Working interest" and is an example of an operating right. The holder of a working interest is responsible for the costs of conducting operations (e.g. drilling a well). In contrast, note that non-operating interests do not bear any portion of the costs to conduct operations.

Non-operating interest

This is an interest which provides no control over the operations of the license. This type of interest does not bear any of the costs associated with conducting operations but is entitled to a portion of the revenue from production. Royalty and overriding royalty interests are examples of a non-operating interest.

Split Estates

Split estates involve situations where the surface rights and subsurface rights (such as the rights to develop minerals) for a piece of land are owned by different parties. In general, mineral rights are considered the dominant estate and will take precedence over other rights associated with the property, including those associated with owning the surface. However, international practice that is generally followed are that the mineral owner must show due regard for the interests of the surface estate owner and occupy only those portions of the surface that are reasonably necessary to develop the mineral estate. This can be an issue where the surface occupant is utilizing the land to grow crops or is using the surface for some other purpose and there is a conflict in use between an oil company and the surface occupant.

Net Profits Interest

An interest where the holder of this interest receives a percentage paid out of the working interest owner's share of net profits. It is non-operating interest and can be created instead of a royalty interest. While it is a type of non-operating interest, it is different from a royalty interest. A royalty interest receives a share of gross revenues while a net profit interest receives a portion of the net profits. The holder of a net profits interest is not liable for paying a proportionate share of losses if the property is unprofitable. However, the contract creating the net profit interest may allow the working interest owner to recover these losses from future payments of net profit.

Volumetric Production Payment Interest

Volumetric Production Payments (VPP) are a type of interest where the holder receives a specific volume of production in a field or property. It is a financial arrangement where a working interest owner sells a portion of the future production for an advance cash payment. It is typically structured to expire after a certain length of time or after a specified volume has been delivered. This type of interest is considered a non-operating interest and is similar to a royalty. Although these types of interests are associated with specific oil and gas reserves, those reserves associated with this interest are not considered part of the proved reserves that a company shows in any financial accounting statements or annual reports. The buyer of this type of interest receives a fixed percentage of actual production, a specified monthly quantity or the equivalent monetary value. This type of transaction allows an oil company to raise capital to develop a property while retaining an ownership interest in the property.

Net Profits Interest

A net profits interest is considered to be an overriding royalty payable out of the working interest income. A conveyance of a drilling site in return for a net profits interest is similar to a situation in which a party who has a mineral license conveys a working interest in the license or an interest in the drillsite and retains an overriding royalty interest in return for another party drilling a well. The party who drills the well would be entitled to deduct 100 percent of the IDC, and the transferor would be considered to have merely retained an overriding royalty interest. If producing properties are conveyed in exchange for a retained net profits interest, the transferor would generally be subject to any recapture provisions of the tax laws in that country.

Production Payment

In acquisitions of oil and gas properties, production payments were frequently retained by the seller as a financing tool. The purchaser of a license was not required to report the income accruing to the production payment retained by the previous license owner. Thus, the oil and gas property could be acquired and paid for out of production that was not taxable to the purchaser. The acquisition of a property burdened by a production payment may, for tax purposes, be similar to the purchase of a property encumbered by a mortgage. For tax purposes, such production payment arrangements may be treated as loans and the payments as loan repayments.

Appendices

Lead Sheet

LEAD SHEET			
CASE:		AUDIT YEAR(S):	
ENTITY:		TEAM MEMBER:	
ISSUE:		DATE PREPARED:	
ISSUE NO:		WORKPAPER #:	

PER RETURN AMOUNTS			EXAMINATION RESULTS	
YEAR(S)	PAGE, LINE, SCHEDULE	AMOUNT	ADJUSTMENT	WORKPAPER REFERENCE

SPECIAL INSTRUCTIONS AND AUDIT PROCEDURES (add or delete procedures as necessary)	IDR #	WORKPAPER REFERENCE	DATE

Conclusion and recommendations for future examinations:

Audit Procedures for Selected Issues

Planning

Review prior and subsequent year's returns of the taxpayer.
Review annual reports (financial statements, SEC 10K, etc.).
Review Petroleum Audit Manual.
Review historical files and prior audit reports and note any carryover adjustments.
Review any emerging industry issues that may be applicable.
Prepare comparative balance sheet analysis with prior and subsequent years and note significant variations for investigation.
Prepare comparative Profit &Loss Statement analysis with prior year and note significant variations for investigation.
Conduct internet search of company, its business environment and major transactions noted in industry publications.
Identify any Pre-Opening Conference topics to discuss with taxpayer (accounting system overview, chart of accounts, business environment, significant transactions, mergers, reorganizations, etc.)
Prepare comparative analysis of tax form deductions and income with prior and subsequent years and note significant variations for investigation.
Identify potential areas or issues for review
Prepare risk analysis and timeline for conducting audit
Prepare administrative documents to be used (e.g. information document request (IDR) log to be used for tracking requests to taxpayer)
Set up case file

Geology and Geophysical

Reconcile amount in tax form to accounting records.
Determine method of accounting used and how costs are tracked.
Determine whether G&G was capitalized or portions expensed. If expensed request explanation and how determination of worthlessness was made.
Inquire into accounting policy for tax treatment of G&G expenses
Inquire whether any G&G expenses were taken as IDC and why
Review AFE's and contracts to acquire G&G data

Acquisitions and Divestitures

Review Large, Unusual or Questionable acquisitions
Determine whether allocation of purchase price to tangible, intangible and goodwill is reasonable and correct
Determine how allocation of purchase price was made and valuation method used
Request copies of Authority for Expenditure (AFE) for acquisition
Review contracts for acquisitions and divestitures
Review any worthlessness determination for divestitures and how derived
Determine circumstance of divestitures and how interest in worthless asset was disposed of

Intangible Drilling Costs

Reconcile amount in tax form to working trial balance.
Review Large, Unusual or Questionable (LUQ) acquisitions to determine that the expenditure is correctly recorded.
Request copies of Authority for Expenditure (AFE) that make up deduction and review tangible and intangible costs
Review drilling contracts and drilling reports

Fixed Assets

Reconcile amount in tax form to working trial balance.
Review Large, Unusual or Questionable (LUQ) acquisitions to determine that the basis is correctly recorded.
If a lump sum purchase price is involved, the allocation (component depreciation) should be reviewed.
Determine company policy with respect to capitalization of minor items and record the information for future reference.
Determine whether tax code requires depreciation to be computed using specific methods for assets used outside the country and if so, identify those assets and methods used.
Determine when assets were placed in service during the year and whether mid-quarter convention applies.
Review intercompany transfers of assets for basis, lives, and methods.

Review asset retirement policy and determine that receipts from dispositions are properly accounted for.
Review asset dispositions. Verify gain/loss calculation and reconcile any book to tax differences.
Review any abandonment, involuntary conversions, and repossessions.
Review Accumulated Depreciation and current year Depreciation Expense.

Intangible Assets

Reconcile amount on tax form to working trial balance.
Review Accumulated Amortization and Amortization Expense.
Secure schedule for items included in this Balance Sheet account. Verify basis of assets placed in service in prior year(s) and lives.
Review current year's dispositions.
Examine contracts relating to asset acquisition(s). Review the allocation of value between fixed assets and intangibles (i.e. goodwill, going-concern value, customer lists, agency-in-force, etc.)
Verify that a determinable useful life exists for the Intangibles.

Depreciation

Reconcile amount per return to working trial balance.
Review the general ledger account(s), including Adjusting Journal Entries, and note any large, unusual or questionable entries. Reconcile differences between book and tax depreciation.
Review any changes in depreciation method to determine compliance with regulations.
Review reserve ratios where Guideline Depreciation is being used.
Review depreciation method, asset life, rates and salvage values.

Income

Reconcile amount in tax form to working trial balance.
.Evaluate internal controls
Conduct a tour of the business site
Conduct a comparative analysis of the balance sheet and income statement
Sample invoices and test for transaction completeness

Review accounts receivable and explanation of large or unusual credit balances
Analyze significant balace sheet accounts that relate to income
Analyze any adjusting journal entries

Accounts Payable

Reconcile amount in tax form to working trial balance.
Review with prior year balances to account for large variations.
Review the items comprising the account. Investigate unusual items.
Review acquisitions and dispositions.
Determine if there are any other expenses that should be capitalized as a prepaid item.

Retained Earnings

Reconcile amount in tax form to working trial balance.
Reconcile beginning balance to the ending balance of the prior year return. Scrutinize any differences as necessary.
Reconcile income per books with the amount reflected on the tax form. Scrutinize any differences as necessary.
Analyze account to isolate increases and decreases for detailed scrutiny.
Probe for expenses that should have been capitalized as the result dividend distributions, reorganizations, etc.
Analyze credit transactions recorded to the account to determine if income items have been improperly recorded to the account.
Review corporate minutes and determine the nature and purpose of any appropriations.

Sales to Related Entities

Determine if transfer pricing issue is applicable with respect to sales made or transfers of assets to affiliates
Test check pricing and compare with sales to unrelated entities.
Determine the correctness of intercompany pricing and allocations and compare with arms-length transactions.
Review transactions and allocations between domestic entity and foreign affiliates. Note if significant problems are discovered.
Determine whether any Transfer Pricing Studies were prepared by taxpayer or consultant and review same
Review any Master Service Agreements with affiliates
Determine if discounted services were performed for affiliates

Legal and Professional Fees

Reconcile amount on tax form to working trial balance.
Scrutinize the account and note any large or unusual items.
Review significant journal entries.
Review account to determine that all monthly entries are posted and verify reversal of prior year accruals and correctness of current year accruals.
Sample items on a selected basis depending upon materiality.
Follow up on adjustments that originate as a result of prior tax examinations.
Cross reference with known acquisitions, reorganizations, stock issuances, long term leases, and whether they should be capitalized.
Determine whether any expenses were directly related to PSA or other exploration or development license or area or production facility.
Determine whether any management fees were made to affiliates, the circumstance surrounding those fees and whether such fees were deducted for tax purposes

Repairs

Reconcile amount on tax form to working trial balance.
Scrutinize the account and note any large or unusual items.
Review significant journal entries.
Review account to determine that all monthly entries are posted and verify reversal of prior year accruals and correctness of current year accruals.
Determine the policy used for determining what constitutes a repair and the unit of property the repair pertains to
Sample items on a selected basis depending upon materiality.
Follow up on adjustments that originate as a result of a prior tax examination.

Dividend Income and Distributions

Reconcile amount on tax return to working trial balance.
Review detail in general ledger accounts and investigate LUQ items.
Determine that dividends received from foreign corporations have been properly grossed up, and reconcile foreign taxes withheld at source.
Determine that proper election has been made if intercompany dividends are excluded.
Test check dividends from unrelated corporations.
Determine the financial capital structure of the corporation and if dividend distribution to parent is a return of capital. Distributions that

are a return of capital are non-taxable. If only portion is return of capital then adjustment necessary to determine taxable and non-taxable portion of dividend

Sales

Reconcile amount on tax form to working trial balance.
Obtain complete explanation of accounting method and insure taxpayer is not deferring income.
Investigate large and extraordinary items and unusual debits.
Examine credit balances in accounts receivable (A/R) to insure they are not used to offset A/R included in gross receipts.
Review year end Adjusting Journal Entries (AJE) for unusual entries/items.
Verify year end accruals and credit memos and trace to inventory.
Test check year-end sales to determine that they are properly handled and obtain pricing.
Determine the correctness of reporting income derived from long term contracts.

Cost of Goods Sold

Reconcile amount on tax form to individual specific trial balance account numbers.

Review items that make up COGS

Review COGS and examine accounts that are material.

Review Cost System and Variance Accounts.

Review general ledger account for unusual entries (e.g. large credit entry), determine the nature and source of the entry

Review the cutoff date to determine if year-end purchases have been recorded in the proper accounting period

Scan purchases column in the cash disbursements journal, general ledger, etc. for unusual amounts, payees or vendors

Review entries in the general ledger. Note and verify entries, which originate from other than usual sources (general journal entries, debit & credit memos, etc.)

Review recorded purchases for a representative period with vendor's invoices and cancelled checks, etc. Note any personal expenses, capital expenses, fictitious or duplicative entries.

Review a representative number of purchases made from related taxpayers or controlled foreign entities. Note any prices in excess of fair market value, excessive rebates, goods or services not received.

Reconcile ending inventory general ledger to per return

Compare beginning and ending inventory with certified financial statements

Review notes to financial statements and determine meaning and significance of any qualifying statements, unusual metrics or revised definitions of terms.
Compare beginning and ending balances for significant decrease, and determine reason for decrease
Compare inventory balances on the return under examination with the balances for the prior and subsequent years' returns and verify with the taxpayer's records.
Determine that the method of inventory valuation conforms to any "prescribed methods" as indicated in Regulation
Check for unauthorized changes from cost to cost or market
Check for gross profit percentage variations
Determine meaning and significance of any notes or qualifying statements on financial reports prepared by independent accounting firms
Determine that all direct, indirect overhead and burden expenses are in the overhead pool that is used in the computation of overhead rates when applicable
Analyze unusual entries to cost of sales account for labor, material, and burden charges not related to sales or transfers of finished goods
Determine that year-end purchases were included in closing inventory
Determine if there have been write-downs for "excess" inventory below cost.
Determine that the method of inventory valuation for "excess" inventory is in accordance with tax regulations
Determine if computations are correct