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Excellence in Taxation

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Suggested Solutions

PART A

Question 1

Royalties

Royalties are usually based on production or value of oil and gas produced. Royalties may be based on different values including:

- Fixed percentage; for example United State Federal royalties.

- A bid amount, applied on several states in the United States; for example Louisiana state royalties.

- Vary with geological features; for example Nigeria offshore royalties decrease with the geological features of greater water depth.

- Sliding scale royalties based on production; for example China and Abu Dhabi.

- Sliding scale royalties based on other several factors; for example Alberta in Canada, based on production and price.

- Sliding scale royalties depending on IRR; for example Greenland.

In the United States, royalties are paid either to the mineral owner, and may be 'Federal' royalties applying to offshore oil fields beyond state territorial sea jurisdiction or 'state royalties' applying to onshore and state territorial sea fields, or are paid to the private resource owner. The royalty may be based on fair market prices, or deemed prices.

Royalties may be based on the well-head price, field terminal price, or the export terminal price. They may also be referred to as severance tax. Several states in the United States impose severance taxes at 2% to 10% of the volume produced, or severance taxes may be based on a percentage of gross receipts.

Excise taxes, are also taxes based on value of production. The term may be used to distinguish the excise from royalties where there are different methods of calculation and revenue sharing arrangements. For example, in the Australia North West Shelf, Federal crude oil excise is imposed on production from the project area. Federal royalties are also imposed, however the royalties are shared with the Western Australia state government.

Royalties are usually combined with other tax systems, such as Concession and PSC regimes. This generally because they give rise to income to the state as soon as production commences, whereas government revenue from Concession and PSC regimes is delayed as the oil and gas company uses carry-forward tax losses or allowable costs from prior years. (Source: Tolley's International Taxation of Upstream Oil and Gas, 2014. Pp, 23-24)

Signature and production bonuses

Many countries require signature and production bonuses as payments to be made at stages of exploration and production. Bonuses may arise as part of the bidding process for a new exploration and development licence, or be imposed under standard terms such as PSC.

Bonuses may include:

- Signature bonuses: payable on signing the oil and gas agreement; for example on signing of the PSC or block exploration and development licence.

- Capacity building bonuses: an amount paid to assist in the development of facilities such as project infrastructure, and generally payable at an early stage in the contract.
- Bonuses may be payable on discovery, commercial discovery, licence application, specific levels of production, or levels of cumulative production.

Signature bonuses may provide compensation for government costs in conducting the bidding process, and will provide income for government oil and gas administration where there are dry wells. The much larger sources of income are production bonuses where significantly higher amounts are paid on meeting oil and gas production milestones. For example, Tengiz contract in Kazakhstan with Chevron requiring a signature bonuses of USD 25m, together with a bonus of USD 210m after 90 days of operation, and a bonus of USD 210m after 12 months.

Bonuses are generally not cost recoverable under PSC regimes, meaning that the oil and gas company does not get cost oil to repay these expenses. Bonuses may qualify for tax relief under tax regimes, for example lease bonuses are amortised for United States federal tax.

Bonuses are significant as an example of amounts which generally apply at levels of production, and therefore are larger if an oil and gas development becomes successful. They are distinguished from royalties, however, as they are not payments for oil and gas resources, and so may be considered to be sharing the benefits of a project when it reaches specific development milestones.

Question 2

Part 1

It is common market practice for IOCs and host states to contractually agree to refer disputes to arbitration. International arbitration is viewed as a trusted neutral forum and tribunal with the benefit of an enforceable decision, not only in the place where it is made but also internationally under treaties such as the New York Convention. International arbitration is particularly favoured where recourse to a host states' local courts may be entirely inappropriate or seen as possibly leading to an unfair result.

In the case of oil and gas, contracts are generally between a private company and a public entity (a government or a NOC). Such contracts concern natural resources of significant value for the host state and, in most cases, the government's biggest source of tax revenue as well as the most important driver of the economy. The income obtained from these contracts is normally paramount for the country's development with significant social impacts on its population. These importance circumstances may in some cases affect the decision process of administrative procedures or court decisions leading to unfair results.

IOCs will go to any place in the world (onshore or offshore) where science indicates that hydrocarbons are more likely to be present. In some situations business is pursued in countries where, if the oil and gas exploration is successful, the administrative and court bodies are unprepared and inexperienced or are dealing with oil and gas issues for the first time. This may lead to scenarios where specific know-how or experience in dealing with oil and gas contractual or tax issues is insufficient. In such circumstances, arbitration provides an ideal forum for the resolution of disputes and the possibility for the IOC and host state to select and appoint an arbitral tribunal with the requisite know-how and experience to ensure a fair and adequate decision for both parties.

An important factor for the choice of arbitration is also the sophisticated international regime in place to enforce decisions. For example, the New York Convention signed in 1958 and in force from 1959 provides for the fast-track recognition and enforcement of foreign arbitral decisions between contracting states. It also foresees the obligation by national courts to refer the matter to arbitration, when requested, where a written arbitration agreement has been signed by the parties.

Part 2

With respect to the impact of arbitration clauses in the tax disputes, it is important to note that oil and gas is a high-risk investment with a small chance of success and characterized by large upfront spending with no guarantee of obtaining any income. Thus, in order to be justifiable, companies need to make sure that the rate of return is adequate considering the risks mentioned above. One of the factors that impacts the rate of return modelled for a specific project is the tax regime applicable to the IOC. The economic model of the prospective investment will include the tax regime applicable and the tax due on the foreseen income. If this tax regime changes through the life of the investment, so will the rate of return for the IOC. Therefore, tax disputes under these types of contracts normally arise when the tax regime for a project impacts the return of the investment in a way which was not initially planned or foreseen. This impact may arise from several different situations, for example different interpretations of the wording of the tax clauses in the contracts or applicable domestic tax law, from lack of clarity or even complete absence of clauses addressing the tax issue arising, or changes brought forward by the legislators in the country (either retrospectively or going forward).

Part 3

The BITs and the ECT are two treaties through which the oil and gas company as an investor in a party country may protect harmful impacts to its investment or rate of return agreed with the Government for a specific project.

BITs are bilateral treaties entered into between states under international law to reciprocally protect investment made by private parties with a view to promoting economic cooperation. The clauses normally included in these treaties protect the investor against expropriation without compensation, unfair inequitable treatment and free transfer of funds. This is generally the case when a country unilaterally increases the tax rate or unlawfully retains VAT refunds in a specific project making it less economically attractive for the oil and gas company. When the tax treatment of the project agreed between the oil and gas company and the Government is unilaterally changed this may constitute a breach of the BIT and the investor is entitled to initiate arbitration proceedings against the host state. Examples of arbitration procedures based on BIT breaches are RosInvest Co UK Ltd v Russian Federation, Duke Energy v Peru, EnCana Corpn v Republic of Ecuador and Occidental Exploration and Production Company v Republic of Ecuador.

The Energy Charter Treaty (ECT) is a multilateral investment treaty focusing on the energy sector and its main objective is to promote and protect investment in the energy sector. The ECT was born from a political initiative by the Dutch Prime Minister in 1991 and was formally signed in Lisbon in 1994 and entered into force in 1998. The ECT provides for international arbitration with an option between ICSID, the Arbitration Institute of the Stockholm Chamber of Commerce or ad hoc arbitration under the United Nations Commission on International Trade Law (UNCITRAL) Arbitration Rules. The main issue with the ECT pertaining to oil and gas projects is that almost all of the signatory countries are European countries. Therefore, it only operates to protect investments made with the European signatory states. It does not cover other areas of the globe where the biggest proven oil and gas reserves are located.

Part 4

In a normal situation, when an IOC enters a bidding round or a direct negotiation with a government for a licence, the contract is normally negotiated with the Ministry of Energy or Ministry of Petroleum. As a general rule, the contract will have a specific part for the tax treatment where several tax benefits may be granted to the project, ranging from special tax rates to tax holidays or customs or VAT exemptions. After signing, where the sanctity of the contractual terms is not upheld and the IOC is denied some of the tax benefits, the State may rely on the lack of competence as a possible defence in arbitration. The host state may argue that taxation matters are under the competence of the Ministry of Finance and that any other Ministries or entities lack the competence to grant tax benefits.

With this in mind it is important, when negotiating, that all the different branches of the government are involved in the negotiations or that they at least give their written agreement to the contract (if possible by participating in the signing). Attention should also be given to specific constitutional requirements related to taxation since in some countries certain tax issues may only be addressed by Parliament and are outside the powers given to the Executive. In some instances tax rulings from the Minister of Finance can be attached to the contracts confirming the tax treatment granted in the tax specific clauses.

Part B

Question 3

The UK imposes corporation tax on profits from all upstream oil and gas activities, referred to as the ‘ring fenced’ trade at 30%. The UK allows an indefinite tax loss carry-forward, and a one year carry-back of losses.

The transfer pricing rules apply to international transactions and transactions within the UK.

The rind fencing provisions provide that onshore losses may not offset offshore profits.

There is a first year capital allowance of 100% for capital expenditure from the ring fence trade. The allowance do not apply to exploration costs, however the research and development allowance at 100% may apply.

Tax consolidation, known as group relief, is allowed for corporate tax and supplementary charge purposes between companies with 75% common ownership.

The corporation tax rules can limit interests’ deductions using a transfer pricing approach requiring ‘arm’s length’ terms. Interest deductions may also be limited under world-wide debt cap rules, but these do not apply to ring-fence companies.

The supplementary charge regime applies to fields which receives development consents from March 1993, in addition to corporation tax, at 32% from 2011. The supplementary charge is not deductible for corporate tax purposes. There is no deduction allowed for financing costs. The effective tax rate of corporation tax and supplementary charge is 62%.

The older petroleum revenue tax (PRT) regime applies under the Oil Taxation Act 1975 to profits on fields which receives development consents prior to March 1993, in addition to corporation tax, at a rate of 50%. The tax applies on a field by filed basis, and is deductible for corporation tax purposes. The oil allowance enables certain levels of production made in the first ten years of field life to be earned free of petroleum revenue tax. The effective tax rate of corporation tax and petroleum revenue tax is 75%.

Question 4

Part 1

Given the fact that the company is reluctant to seek additional funding there could be a worthy alternative to consider to get access to the necessary cash for the upcoming well. The possible alternative would be to use a tax incentive available in Norway that differentiates this oil and gas tax regime from other jurisdictions in the world. This tax incentive allows for the refund by the Government of tax value of exploration costs. Norway allows a licensee to claim a refund of the tax value of the tax value of exploration costs incurred as an alternative to carrying forward the losses until profit from sale of oil is available. Thus, the refund available is 78% of the exploration costs equal to the combination of the taxes applicable to oil and gas revenues of 27% (Ordinary Petroleum Tax) plus 51% (Special Petroleum Tax). It is important to note that the refund is available for all direct and indirect exploration cost with the exception of finance costs which means the company could not get a refund on the $25m paid as interest. Assuming, the company has $250m of accumulated exploration costs the available refund would be $195m which would allow the company to have cash to fund the next exploration well without seeking additional loans. We should also note that, as an alternative to a group loan, the possibility of obtaining this refund has also been used as collateral in the past to obtain loans with banks which are normally willing to lend up to a certain percentage of the tax value of the current exploration costs.

Part 2

Under Norwegian law you do not have specific transfer pricing or thin capitalization rules, Notwithstanding, in group loans for the interest expense to qualify as a deductible expense it must abide by the international principle of arm's length conditions and not exceed what a an unrelated party would offer in normal market conditions. One other problem which has been affecting some of these loans pertains to group guarantees for loans with third parties where the guarantee would not be given as collateral to the company taking out the loan in an arm's length situation given the fragile financial situation of the company. One other aspect to consider is the limitation applicable under Norwegian law for the deduction of finance costs. This limitation applies with regard to the Special Petroleum Tax and limits the deduction of net financial costs allocated to upstream activities according to the following formula:

$$\text{Total net financial costs accrued} \times \frac{\text{50\% of tax value of the qualifying assets}}{\text{Average total interest debt during a year}}$$

The interest expense not deductible according to this formula may only be used against income from other activities (onshore income) at the normal rate of 27%. Even if the company does not have any activities other that the upstream project it may still have income considered onshore income (e.g. hedging gains). The amounts not deducted because of this limitation may be carried forward for deduction in upcoming tax years but only against the Ordinary Petroleum Tax (leaving out deduction for Special Petroleum Tax purposes).

Part 3

In Norway there is no limitation in the carry forward of losses and these can be taken forward indefinitely and thus if the exploration costs were not refunded under the tax incentive mentioned above they will be deductible against profits. In addition, the Government pays interest on the annual balance of the losses according to a rate fixed annually by the Ministry of Finance. With respect to production and development expenses the tax deduction is taken in the form of capital allowances and, as a general rule, depreciated over a 6 year period starting in the year in which they are incurred. Under the Norwegian rules and for the purposes of Special Petroleum Tax, the company is also entitled to an uplift of the production and development expense equal to 22% of the expense amount. This means that the tax value of a production expense may go up to 89.2% instead of the normal 78% (27%+51%).

PART C

Question 5

Part 1

A lease is classified as a finance lease if it transfers substantially all the risks and rewards incident to ownership. All other leases are classified as operating leases. Classification is made at the inception of the lease [IAS 17.4]. Whether a lease is a finance lease or an operating lease depends on the substance of the transaction rather than the form.

Finance lease: the lessee will eventually obtain ownership of the asset, and the lease is therefore treated as a form of financing.

Under this lease, transactions generally result in additional debt on the balance sheet of the lessee, as the transaction is treated as a loan to acquire the asset under the finance lease agreement. In finance leasing transaction, only the interest component of lease payments are deductible for tax purposes.

Situations that would normally lead to a lease being classified as a finance lease include the following [IAS 17.10]:

- the lease transfers ownership of the asset to the lessee by the end of the lease term;
- the lessee has the option to purchase the asset at a price which is expected to be sufficiently lower than fair value at the date the option becomes exercisable that, at the inception of the lease, it is reasonably certain that the option will be exercised;
- the lease term is for the major part of the economic life of the asset, even if title is not transferred;
- at the inception of the lease, the present value of the minimum lease payments amounts to at least substantially all of the fair value of the leased asset; and
- the lease assets are of a specialised nature such that only the lessee can use them without major modifications being made.

Operating lease: the lessee is merely renting the asset and is not likely to obtain ownership of the asset at a future date.

Treatment as an operating lease for tax purposes generally depends on establishing that there is not an economic sale of the asset to the lessee.

Operating leasing has generally provided an advantage for lessee companies as the transaction is treated as mere rental of an asset which did not result in debt on the lessee company's balance sheet. Operating leasing is significant for tax purposes as the related payments are generally deductible, as the lessee is treated as merely renting the asset.

The lessee under operating leases is not treated as the asset owner. Accordingly, the lessee will not obtain any depreciation deductions based on amortising the value of the asset.

Operating leases may provide tax advantages compared to finance leases where the increased deductions of the full operating lease payment is greater than the interest component and depreciation deductions under a finance lease.

Part 2

For lessee, the Exposure draft proposes the recognition of a liability and a right-of-use for all leases with a profit or loss impact dependent on the classification of a lease. These leases accounting rules generally require that at a commencement date of the lease, the lessee discounts the lease payments using the rate that the lessor charges the lessee, or if that rate is unavailable, the lessee's borrowing rate. The lessee then recognises the present value of lease payments as a liability, and at the same time, recognises a right-of-use asset equal to the lease liability.

Operating leases are not recognised as an asset in the company's balance sheet.

Question 6

Tax due diligence

1. Essential tax applying to the proposed investment, including rules for recovery of exploration expenses, treatment of capital expenditure, carry-forward losses, repatriation of profits, capital gains, transfer taxes, and indirect taxes such as VAT.

2. Hydrocarbon tax ring fence issues, such as restriction on interest deductions against ring fence income.

3. Determination of the holding structure, including election of a branch, single company or double company holding structure, consideration of taxation on income flows, withholding taxes, potential capital gains taxes on exit, and the funding structure of the investment.

4. The holding structure used if there are local or foreign partners.

5. Whether an intermediate holding country should be used for dividends, capital gains tax and related tax treaties.

6. Preparing a tax leakage calculation for the preferred structure, e.g. calculation from 100% of oil and gas income, reduction for taxes including any profit oil sharing under PSC regimes, calculating back to the net after tax cash to be received in the parent country.

7. Determining whether the seller is taxable in its own country of residence or the country where its assets are located, and estimating the amount of tax.

8. Reviewing transfer taxes or stamp duty applying to the sale and related asset or share transfers, including the estimated amount, and whether these amounts are payable by the seller, the buyer, or are shared.

9. Determining any carry-forward tax losses under a tax and concession regime, or allowable costs under a PSC regime, in the transferred company or licence asset, and reviewing whether these amounts are preserved by the transfer, and whether there is any group relief, tax consolidation, or tax loss contribution available in the new holding structure.

10. Reviewing what related party and external funding requirements apply for the acquisition and anticipated future expenses.

11. Reviewing whether any interest payments on funds to acquire the company or asset is deductible under local country rules. Some countries limit deductions based on purpose of the loan, or if related party. Reviewing whether the debt and interest deductions have been pushed down to the profitable company.

12. Consideration whether required loans are within this capitalisation rules in the borrowing country. These rules can generally disallow interest deductions on related party loans where a company's debt exceeds certain levels.

13. Reviewing whether there is an opportunity to increase the value of transferred assets to their market values to allow increased future depreciation deductions as an asset step up for tax purposes, for example by using an asset transfer rather than acquiring the company, or an asset transfer after the acquisition.

14. Consideration of any Goodwill in the transferred company, or asset such as a licence, and whether any tax relief available for the goodwill such as goodwill tax amortisation.

15. Consideration of transfer pricing issues in the new structure, particularly whether any intra group asset transfers or payments will be at arm's length prices.

Question 7

There are several different ways a transfer of a license may occur and the tax impact of the transfer will vary depending on the specific country legislation or applicable petroleum license contract.

Before going into the different ways this transfer can be executed it is important to note the tax impact of the operation, as general rule through the taxation of any capital gains, may be significantly impacted by specific issues which stand outside the applicable tax framework. For example the market value of the license itself may be lower than the price being paid by the third party entering the license specifically in license where a discovery as not yet been made by the current holder making the capital gain non-existent. One other aspect is the specific agreement made between the Government and the current holder of the license which may foresee a special regime for the tax treatment of capital gains outside the treatment of capital gains according to the domestic tax legislation.

The taxation of a transfer or a license can be done through several different taxes depending on the jurisdiction (e.g. capital gains tax, corporate income tax, stamp duty tax, value added taxation, etc.) and can also be impacted by the double tax treaties entered into between the country where the license is held and the country where the license owner is a resident.

The first and most obvious way to transfer would be a direct transfer of the asset (license right) to the third party for a cash consideration. As a general rule in a transaction like this the consideration received will be subject to tax through a capital gains tax or corporate income tax. Attention should be paid to impacts of the depreciation of past costs, and signature bonus given that in some countries a deduction is not given for past costs spent with the license when assessing the capital gain.

The second way would be to execute an indirect transfer of the license by transferring a participation in the company which hold the license instead of selling the license directly. In this specific situation focus will be on possible taxation of capital gains arising from the sale of shares and the impact of double tax treaties in this transaction. Specifically when the holder of the license is a company outside the country where the license is held.

In both cases the parties should always consider tax impacts related to unrelieved losses or capital allowances as limitations may exist in the utilization of these losses by the acquirer of the license and to the interest deductions structures (debt push down).

With respect to possible ways to structure the transaction to optimize the tax impact of the operations for direct transfers the parties could agree to a cost carry type of deal. This is common in farm down agreements where the current holder is only transferring part of the currently held license to a third party In a cost carry deal there is a transfer of part of the license for a non-cash consideration. As a general rule the Farminee agrees to carry the Farminor up through the rest of the exploration phase of the license. This means that the Farminee will pay a higher share of the costs than the ownership share it is acquiring or in other instances it agrees to pay future royalties liabilities. The reason why these types of deals are more difficult to tax is that, as general rule, the tax laws do not foresee the taxation of a transaction without a consideration paid in cash. The risks of these deals are possible anti avoidance provisions or transfer pricing rules that may nonetheless grant a cash value to the deal and subject that amount to tax under capital gains tax or corporate income tax. The risk is higher in situation where caps for costs or royalties to carry are established in the farm down agreements which makes it easier to determine the market value of the deal.

For indirect transfers of the license in some countries legislation has been put in place to allow the taxation of share deals for assets located in that country (e.g. natural resources) even if the parties are not resident (e.g. UK and Mozambique). Possible solutions could be to use a double tier structure. So instead of selling the shares of the licence holder you sell the holding company of the company owning the license given that most tax legislation applying to indirect transfers will only tax first tier share deals. Other possible solutions would be to use the double tax treaty to exempt capital gains taxable under the domestic tax legislation as some agreement expressly exempt non-resident capital gains obtained on the sale on movable property.

Question 8

Part 1

Normally, expenses for decommissioning of oil and gas installations and wells are very high, especially in offshore areas. With the proliferation of strict requirements put in place by new environmental laws the costs of decommissioning have been rising. Also, Governments are always concerned with making sure the operator makes the necessary preparations for the decommissioning of the installations and well to avoid environmental disasters. These factors have contributed for the increase in the last decade of the amount of decommissioning costs which are incurred by oil and gas companies.

From an accounting perspective companies create a provision for the future liability costs and recognize a deferred tax asset on the future liability but if the provision is not accepted for tax purposes the problem will remain. The tax impact when addressing the decommission process is the recognition of the expenses. Because the decommissioning expenses are made at a point where the oil production is reduced to a very small amount or none at all, the main problem arising is that the profits from the sale of oil may not be enough to deduct the decommissioning expenses leaving the company with unrelieved losses for which it will get no tax benefit. This together with the fact that the tax deduction for the decommissioning expense is only given at the time when the expense is incurred creates possible tax issues for the company.

From the Government side the fact that in most cases the tax rules disallow the deduction of accounting provisions or reverses made for decommissioning costs creates uncertainty in this topic and raises concerns that the companies will have profits to be able to pay the decommissioning of the oil and gas installations at the end of the field life.

Part 2

On the possible solutions to deal with this problem which some countries have been adopting is to create a decommissioning fund. This works by having the companies contributing cash to this fund for future estimated decommissioning expenses early in the project (e.g. when the reserve reaches 50% depletion) to allow for an early tax deduction of the cost when the oil production is still high. This also covers the risk of the Government by linking the deductibility of reserves to the abandonment contribution plan agreed with the oil and gas company and guarantees that the cash for decommissioning will be available when needed. To address cash flow issues this cash may be lent back to the companies in exchange for an interest payment. Examples of this solution include Canada and Ghana.

One other solution is to allow the carry back of the expenses against past profits until these costs have been fully tax deducted. In this case losses arising in the year of cessation of trade or losses that arise from decommissioning expenditure can be carried back for a number of periods agreed by the Government. Thus even if the decommission expenses are only deductible when they are effectively incurred the Government guarantees that they will be tax deductible against prior year profits making sure the company is not left with unrelieved losses. An example of this was applicable in the UK.

A different solution has been adopted by Norway where if the decommissioning costs are not recovered through the deductions in different field still in production the Government will refund the oil and gas company for the tax value of the decommissioning costs similarly to what happens with the explorations costs incentive.