THE ADVANCED DIPLOMA IN INTERNATIONAL TAXATION

December 2020

MODULE 3.04 – UPSTREAM OIL AND GAS OPTION

SUGGESTED SOLUTIONS

PART A

Question 1

Part 1

There are three main international oil and gas agreements: Concession, Production Sharing Agreements and service contracts.

A concession is a grant by a country to a foreign company to develop its oil and gas reserves on an exclusive basis in a defined area during the duration of the agreement. According to concession regimes, title to oil and gas is transferred to the international oil and gas company. Title is given to the extracted oil and gas but not to the total oil and gas exist in situ. Companies acquire rights to control large areas of land/sea to carry out their operations over a relatively long period of time (up to 75 years in some cases). The contractor pays all the costs associated with exploration, development and production activities without any guarantee from the host government to recover any of these costs.

According to PSA the government retains titles to oil and gas reserves but gives the contractor a share to production, known as profit oil. The international oil and gas company bears all the pre-production risks and costs and when commercial reserves are discovered the contractor is entitled to recover its costs via cost oil. The remaining oil and gas (the profit oil) is split between the international oil and gas company and the host government according to a pre-agreed formula, this can be fixed percentage or on a sliding scale basis. The company still has to pay taxes on its share of the profit oil; in some cases company's taxes is paid by host government from their profit oil share.

In service contracts the international oil and gas company is paid fee by the host government for providing services in form of exploration, development and production activities – these are called non-risk service contracts. In risk-service contracts the oil and gas company receives its fees only upon discoveries of commercial oil and gas reserves. Oil rich countries use these types of contracts due to their lack of technical experience in the oil investment businesses. Under these contracts the contractor may receive his fee in cash or kind (oil and gas), while under PSA no cash is paid by host government to the contractor for his share – profit oil and gas (in kind payments) is shared between the parties.

Part 2

Export Duty

Export duties on oil and gas are taxes on amounts of production exported from the producing country. They are generally combined with other taxes, as in the following example for Russia:

- A substantial portion of the Russian income from upstream oil and gas is made under the Export Duty regime at rates from 35% to 60% on crude oil, and natural gas at 30%. There is no export duty on LNG.
- The Russian government also impose Mineral Extraction Tax, which are royalties based on crude oil RUB 446 per tonne, natural gas RUB 509 per 1,000 cubic metres, etc.
- Russia also impose Corporate Profit Tax at 20%.
- The Russian government has provided exemptions from export duty for crude oil with specific characteristics, and in relation to production from specific regions.
- Export duties are substantially different from indirect taxes such as VAT, which may provide exemption for exports.
- The duty is imposed for the right of the country's oil and gas, rather than as a tax on production as VAT.

- The amounts are imposed as an export duty so that domestic oil and gas prices are not directly affected, and therefore target large scale oil and gas developments aimed at generating profits from international oil and gas sale.

The issue of oil and gas developments impacting local prices is seen in a large number of countries. For example the United States, where the potential issuing of LNG export permits and terminal approvals is expected to increase US domestic prices. The use of an export duty may partially address this issue by ensuring that part of the taxation does not apply to domestic oil and gas sale.

Indirect Taxes and VAT

Value Added Tax (VAT) is imposed in many countries on the value of a company's sales, with the company allowed a credit for VAT paid on their purchase. VAT therefore applies to the value added by each stage from production to final sale.

The export of oil and gas may be 'zero rated' for VAT purposes. The result is that VAT is not chargeable on the export sale, however the company is entitled to a refund of the VAT paid on its related purchase. Zero rating may then result in a credit refund issue.

The oil and gas company may be applying for refunds, as it has paid VAT on its purchases, but does not charge VAT on its sale where export sales are zero rated. The issue is whether refunds are allowed, are provided promptly, or there are substantial delays.

There may also be an issue that VAT refunds may be restricted to the related joint venture, rather than made available to the investing companies.

Tax regimes and PSCs may therefore provide specific exemptions from VAT to avoid this credit refund issue. This may be extended to local suppliers to upstream oil and gas companies.

Alternative methods of indirect taxation include the gross turnover taxes applied in many states in the United States. These are essentially single stage taxes on the final sale to the consumer.

Countries may also impose significant customs duties on importation of equipment for exploration and production. Several countries allow specific exemption under PSCs or tax regimes from indirect taxes such as VAT where equipment used in oil and gas activities is subsequently exported after use. Examples: The Brazilian Repetro regime, and the Indonesian Import Duty.

Customs duties are a significant issue for the importation of oil and gas, and a related issue is whether there are exemptions from customs duty under international agreements. Examples: the related exemptions between Canada, Mexico and the United States under the North American Free Trade Agreement.

Related issues include whether crude oil and natural gas qualify as sources in a NAFTA country under NAFTA rules of origin. For example, when oil and gas companies blend crude oil with condensates or diluents from non-NAFTA states to transport the oil by pipelines, or blend natural gas with gas origination in non-NAFTA states.

Question 2

Transfer Pricing principles, rules and methods are today inevitable for oil and gas companies. Most countries in the world have adopted transfer pricing local rules, normally based on the OECD principles. These rules apply to transactions on goods and services between related parties. Under the transfer pricing principles, a transaction between related parties should occur at "arm's length", meaning what would have been paid if the parties had not been related.

Countries objective is to prevent profit shifting to lower tax rate jurisdictions. Where a company established in a high tax rate jurisdiction tries to reduce tax by paying above-market prices for goods and services purchased from a related company in a low tax rate jurisdiction, the transfer pricing provisions prevent excessive tax deductions by limiting tax costs to levels that an independent company would have paid for the same goods and services. This could lead to a double tax scenario if a corresponding adjustment is not made.

For countries with an oil and gas activity, the sum of government take in oil and gas is normally higher than in other areas of the economy. This drives companies to look at optimisation opportunities for shifting profits from high tax jurisdictions. The transfer pricing rules also look at avoiding excessive tax deductions for highly leveraged debt finance at above-market interest rates, claiming of excessive management fees, group costs, or consultancy charges paid between related entities.

Oil and gas services are an essential part of the oil and gas activity. These include exploration services by way of seismic surveys, geological and geophysical studies. It also includes drilling services where an oil and gas company provides technical services to a subsidiary. The key transfer pricing consideration for oil and gas services the deducting these costs under the PSC or Petroleum Agreement in the host country. The services charged between related parties must be at arm's length prices when compared with similar services provided by independent parties. Each company charges different types of markups on services provided by their staff. Companies should aim to have a transfer pricing file evidencing that the mark up charged is within market range when compared to similar services hired by independent parties.

Other types of intercompany services include administration and commercial group functions like accounting, payroll, human resources, training, tax and legal, marketing and insurance services. The OECD principles state these intercompany services should be directly charged (paragraph 7.23 of the OECD Transfer pricing guidelines). In examples like Norway, the country may artificially fix what is the maximum mark-up chargeable in intragroup service transaction. This could be a challenging situation where the market price is above the maximum acceptable tax deduction by the tax authorities.

Because of the long lead times and high risk of oil and gas operations, companies normally enter Joint Ventures with other oil and gas companies. This can also lead to service charges between JV partners who need to be comparable to charges between unrelated parties and auditable by Governments and JV parties.

Guarantees are another area where transfer pricing provisions can be relevant. Oil-producing countries require oil and gas companies to provide financial and environmental guarantees. Where a parent group company is providing a guarantee in the name of one of its subsidiaries, charged fees will come under scrutiny. It can be argued that in this situation there is no comparable, as no third party would incur such risk. The fee may also be subject to reductions as implicit "free" support by the parent company is also expected in a group relationship. see case The Queen vs. General electric capital Canada 2010 for the relevant jurisprudence.

Oil and gas project financing are highly impacted by transfer pricing rules and guidelines. Generally, oil and gas companies secure a centralised loan based on their proven reserves. The companies then distribute those funds throughout the projects of the company and the different subsidiaries. Transfer pricing rules may deny the deduction of interest paid to related parties if the interest rates are agreed on an arm´s length basis. The determination of an arm's length interest rate takes into consideration several factors. These factors include the repayment terms of the loans, the loan duration, any loan covenants, what type of guarantees are offered, the credit risk of the borrower and the country where the company is operating, market conditions, foreign exchange risk and risk of the investment itself.

Exploration phase loans and whether interest should be charged is another area of group financing whether transfer pricing guidelines may have an impact. The problem is whether it can be argued the loan should bear no interest and be considered equity as no third party would lend the company funds for such a risky operation. Grossing up of the withholding tax is also something that has been discussed concerning intragroup loans. In a normal loan between unrelated parties, any withholding tax applicable in the host country would be expected to be grossed up.

Other transfer pricing relevant challenges for oil and gas include the use by some PSCs or agreements with official sale prices for corporate income tax purposes. These fixed prices may differ from market price and create a tax issue. Another potential issue is the use of group trading companies to trade oil where the trading company does not have enough third party comparable on fees and margin charged.

PART B

Question 3

Part 1

United States federal income tax applies under the Internal Revenue Code (26 USC (1986), to upstream oil and gas activities at standard corporate rates, at 35% for corporations with taxable income over USD 18,333,333; 34% for companies with taxable income above USD 335,000 and lower marginal rates in other cases.

Tax deductions are allowed for state and municipal taxes

Tax losses can be carried forward for up to 20 years, subject to continuity of ownership, and carried backward for up to two years.

Tax consolidation applies for affiliated groups where there is at least 80% common United States parent ownership.

Thin capitalisation provisions can potentially apply to disallow interest deductions where related party debt generally exceeds a safe harbour debt to equity ratio of 1.5 to 1.

There is no ring fencing between oil and gas fields or upstream and other activities.

Assets calculations are made on a unit of property basis, including the property basis or cost, gains or losses on disposal, abandonment, and property-related deductions (such as depletion, depreciation and amortisation). The unit of property basis in upstream oil and gas is frequently the related lease or oil and gas well.

Depreciation allowance may be based on units of production determined by current year production over total remaining reserves, or under the modified accelerated cost recovery system which generally uses a declining balance system.

The Alternative Minimum Tax (AMT) regime may apply at a 20% rate on profits, instead of income tax, if AMT is the higher amount. The calculation base of AMT excludes several incentives, and can apply to oil and gas companies which would have a low income tax due to IDC deductions or carry-forward tax losses.

Federal royalties are generally imposed at 18.75% of the value of production for offshore beyond state maritime boundaries.

Part 2

Federal tax incentives for upstream oil and gas operations include:

- The intangible drilling costs (IDC) incentive: applies to costs which are 'incident and necessary for the drilling of wells and the preparation of wells for the production of oil and gas.' This incentive allows and election for 100% current year production. The current year production is reduced to 70% for 'integrated oil companies' which have over USD 5m annual retail oil and gas sales, or refining operations in excess of 75,000 barrels/day, with the remaining 30% required to be amortised on the same basis as lease and well equipment over five years.

- Exploration cost amortised: over two years for independent oil and gas producers, and over seven years for integrated oil companies.

- Percentage depletion: available to independent oil and gas producers and royalty owners. This allows deductions at a fixed rate of income, based on the extent of depletion of oil and natural gas. This is an alternative to cost depletion on a unit of production basis, also used by integrated oil companies, which allows deductions of costs based on annual production over the project life.

- The enhanced oil recovery credit: a tax credit generally at 45% of qualified costs, which include specific tangible property, intangible drilling and development costs, and qualified tertiary injectant expense.

- Domestic manufacturing tax deductions: at 6% on related oil and gas income. The deduction is generally limited to 50% of wages.

Question 4

Part 1

Ring-fencing rules enforce a limitation on tax deductions for corporate income across different activities or projects undertaken by the same oil and gas company.

Contractors or concessionaries are required to restrict all cost recovery and or deductions associated with a given license (or oil and gas field) to that area. This means that all costs associated with a field or licence must be recovered from revenues generated within that same area.

Different scopes can apply to ring-fencing provisions. Some countries ring-fence their oil and gas activities from other non-oil and gas activities performed by the same company (e.g. downstream operations) in the country, whilst others may ring-fence individual oil and gas projects from other similar projects held by the same company.

In a ring-fencing situation, exploration expenses in one non-producing licence/block may not be deducted against income from another licence/block.

Under Production Sharing Contracts ring-fencing acts similarly, as a cost incurred in one ring-fenced block cannot be recovered from another block outside the ring-fence.

Main impact for the oil and gas companies is a potential higher tax on the projects. If a company operates in several ring-fenced areas it must calculate profits separately for each area and may not consolidate the cost for tax calculation purposes.

If all the projects held by the company are profitable, this impact would create a timing issue, as the costs will still be recovered later in the project timeline.

By allowing companies to offset costs across several licences will give an advantage to existing industry players over new entrants with only one license.

For governments, these rules have an impact because the absence of ring-fencing can postpone government tax receipts. The company that undertakes a series of projects can deduct exploration and development costs from each new project against the income of projects that are already generating taxable income delaying collection of tax revenue. Ring-fencing rules introduced by Governments will accelerate revenue collection.

In case different tax regimes apply to different licences/areas, the lack of ring-fencing rules would make oil and gas companies allocate costs disproportionately to higher-taxed areas to reduce tax.

Where countries impose progressive taxes, ring-fencing can mean that companies pay high taxes on "excess profits" from one area, even though they have not made excess profits (or have even suffered a loss) in the country.

Ring-fencing may hinder companies undertaking further exploration and development activities due to the inability to claim deductions for such activities on new projects. Ring-fencing adds significant administrative complexity and risk to tax compliance, for example where one tax (such as a resource rent tax) is ring-fenced but another tax (such as the CIT) is not.

It may also encourage tax planning if the ring-fenced tax regime is more onerous than the standard tax regime. For example, locating lower-taxed downstream activities outside the ring-fence, including in another jurisdiction, or transfer pricing to shift profits outside the ring-fence or costs inside the ring-fence.

Part 2

Examples of ring-fencing provisions or regimes include:

- Denmark applies ring-fencing provisions so that losses from non-oil as gas activities cannot offset profits from hydrocarbon production.

- Greenland, there is no field ring-fencing, but oil and gas explorations income or costs may not be offset against income and cost from other activities.

- Kazakhstan applies ring-fencing between Production Sharing Contracts individually and between oil and gas production and exploration and other activities.

- Norway has a different way of applying ring-fencing limitation. Only 50% of onshore losses may be used to offset offshore profits in a clear incentive to prefer offshore exploration.

- Qatar, which uses Production Sharing Contracts, ring-fencing provisions do not allow the communication of costs to offset profits of a different contract.

- UK ring-fencing provisions provide that onshore losses may not offset offshore profits but there is a first-year capital allowance of 100% for capital expenditure from the ring-fenced trade.

Examples of oil and gas producing countries with no ring-fencing provisions include Brazil, Saudi Arabia and the United States.

PART C

Question 5

Part 1

A building site, or construction or installation project constitute a permanent establishment if it lasts for more than 12 months.

An enterprise may be treated as having a permanent establishment through the activities of a dependent agent which habitually exercise authority to conclude contracts on its behalf. This provision does not apply to an independent agent acting in the ordinary course of their business.

There are several exclusions from the definition of permanent establishment, including a place of business solely for activities of a preparatory or auxiliary character, also known as a representative office.

A representative office which does not have the authority to negotiate or conclude contracts on behalf of its head office company may not be treated as a taxable permanent establishment.

An example of representative office relating to upstream oil and gas may, for example, be an office of a drilling services company. The representative office advertises the company's services to oil and gas companies, and then arranges contracts with head office staff. The head office then negotiates and concludes contracts with oil and gas companies.

A related structure is to use a separate company to provide the local country services, so that the drilling company itself does not have employees or a permanent establishment in the country. The drilling company may then transfer or second employees to local company employment contracts when they are required for specific projects. The local company may be taxed for the work performed relating to that country, however the parent drilling company should not be taxed as there is no permanent establishment in that country.

The use of tax treaty provisions depends, of course, on the experience of a tax treaty between the related countries. A multinational group may therefore have companies which can provide related services based in several countries, and use the company located in a treaty country to provide the related services.

Part 2

Companies providing services such as seismic survey and drilling may potentially be taxed in the country where services are performed on the basis of a permanent establishment.

There is an issue as to whether a country's tax laws may treat a foreign company to be taxable on work done overseas, and not just by the permanent establishment.

Certain tax treaties may contain force of attraction provisions, which allow local county taxation on income with a source in the country but not derived by a permanent establishment in the country, where that income is of the same nature as income derived by the permanent establishment.

Local joint ventures are usually fully taxed in their local countries. Local country withholding tax may apply to contractor payments.

'Grossing up' for local withholding tax applies to payments including technical service fees, interest payments on loans, royalties on use of patents and trademarks, and lease payments for substantial equipment, such as the provision of drilling ships and floating production, storage and offloading vessels.

Contracts may contain a specific gross up clause for withholding tax, which could result in denial of full deduction from allowable costs to the extent of withholding tax. One approach is to effectively include the grossing up as a tax deductible expense as part of overall price. Parties would therefore agree on fixed price schedules that are already adjusted for withholding tax.

An oil and gas company may seek recovery if the supplier receives a credit for the local country withholding tax.

Question 6

Part 1

The decommissioning issue relates to whether deductions are available and the timing of such deductions for decommissioning oil and gas installations. The related expenses include removing topside installations, well plugging, decking, concrete caissons or steel jackets, pipelines, and sub-sea equipment.

Decommissioning requirements are becoming more extensive, with new environmental laws being introduced, and there is increasing responsibility for decommissioning under international conventions.

Generally, the cost of decommissioning is deductible when they incurred at the end of the oil and gas field life. Annual provision is required for accounting purposes; this provision is non-deductible for tax purposes in most countries. When decommissioning costs incurred they are allowable for tax purposes.

Where oil and gas companies make annual prepayments of future decommissioning expenses to a decommissioning fund, deductions for tax purposes may be made over the life of the oil and gas fields to match the provisioning required for the accounts. Some countries do not allow deductions for prepayments.

Part 2

Payments for the use of intellectual property potentially may be made as royalties or management fees. These payments are generally deductible in many countries using concession and tax regimes. There may be restrictions on whether these payments qualify as recoverable costs allowing costs oil recovery under production sharing contract regimes.

- There may be a tax planning preference for a structure where royalties are paid for the use of intellectual property to an intellectual property holding company located in a tax-effective country, or for management fees where this incurs lower withholding tax than royalties.

Part of the M&A transactions is to review the intellectual property that may be acquired from the target company. The major consideration is whether any acquired intellectual property can be transferred to a holding company.

Structures used for intellectual property vary between multinational groups with head offices in different countries (students can give examples here)

It may also be possible to separate payments for intellectual property from time-based charges. For example: large oil service companies may separate the intellectual property used in oil filed drilling tools from the tools themselves, and then license the intellectual property to the companies that use the tools.

Part 3

In general, the repatriation of profit is not deductible in the paying country, however it may be exempted in the parent country.

There may be scope to reduce taxes in the local country by maximising amounts that may be deductible, such as management fees and interest on loans.

The repatriation of profits depends on the tax laws of the countries concerned, including the rate of tax on oil and gas activities, the imposition of royalties and severance taxes, how profit oil is shared under PSC regimes, the withholding tax on dividends and other payments, etc.

The repatriation of branch profits is not treated as a dividends and in many countries this repatriation of profits may not be subject to local country withholding taxes.

A head office company may, together with related companies, incur expenses relating to the local branch, such as administration, accounting, human resources, legal, and IT expenses. Most tax treaties allow allocation of expenses related to the Branch as deductible in determining local country tax on the Branch.

Question 7

Interest deductions are generally allowed to a company for the purchase of assets under tax and concession regimes, as the assets will generate taxable profits. It may be harder to achieve interest deductions for the purchase of shares in a target company, as there may be restrictions where the related dividends are tax-exempt under participation exemption provisions.

Interest deductions can be used against profits of the acquired company if the country allows the use of tax groups or tax consolidation under its domestic rules.

The possibility of using interest deductions in PSC regimes is harder to achieve. As a general rule, the PSC should exclude financing costs as allowable costs in determining cost oil. Interest deductions on debt to acquire licence interests subject to PSC regimes can also be made elsewhere in the multinational group.

The existence of thin capitalisation provisions can restrict or limit interest deduction on related-party debt making harder to obtain tax utilisation of the interest expense.

Debt push down is achieved by the placing of third-party debt within a multinational group, such as borrowing from banks. In some jurisdictions, interest on this debt may be outside the scope of thin capitalisation provisions.

The objective here is to use a debt push down structure to utilise interest deductions in a target Company to offset that company's profit.

The acquiring company may obtain a tax deduction in its own country but without being able to effectively utilise the deductions if it does not have significant taxable income.

To push down the debt, the acquiring company incorporates a new company in the target country (SPV). The SPV then purchases the target company, or the oil and gas assets, on behalf of the acquiring company.

If the target company is acquired then tax consolidation is generally needed to transfer accumulated tax losses arising from interest deductions in the SPV to reduce tax in target company.

The timing of adding debt and related interest deductions is important depending on the stage at which the upstream oil and gas target company is. If in exploration or early production stage, with large carry-forward losses, there may be an advantage in increasing related party debt at a later stage when the target company is profitable and deductions can be utilised.

Question 8

The tax impact of the operation, as a general rule through the taxation of any capital gains, may be significantly impacted by specific issues which stand outside the applicable tax scope. For example, the market value of the license itself may be lower than the price being paid by the third party entering the license (e.g. where a commercial discovery as not yet been made).

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 achieved through 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.

A direct transfer of the asset (license right) to the third party for cash consideration. In this type of transaction, the consideration received will be subject to capital gains tax or corporate income tax.

There can be impacts of the depreciation of past costs and signature bonus paid where a deduction is not given for past costs spent with the license when assessing the capital gain.

An indirect transfer of the license by transferring participation in the company which holds the license instead of selling the license directly. In this situation, the 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.

When the holder of the license is a company outside the country where the license is held it may be subject to different treatment.

In direct or indirect transfers the parties should always consider tax impacts related to unrelieved losses or capital allowances. Limitations may exist in the utilisation of these losses by the acquirer of the license and to the interest deductions structures.

Possible ways to structure the transaction and optimise the tax impact of the transfer may be to 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. 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 that the ownership share it is acquiring or in other instances it agrees to pay future royalties liabilities.

These types of deals are harder tax because the tax laws do not foresee the taxation of a transaction without any consideration paid in cash. Possible application of anti-avoidance provisions or transfer pricing rules may nonetheless attribute 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 a 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.

In indirect transfers of an oil and gas license, 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 non-residents (e.g. the UK and Mozambique).

A possible solution 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 solution would be to make use of a 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.

In addition to corporate tax, VAT and possible stamp duties impacts should also be considered to make sure the full consideration of the cost to be paid is made by the parties in the transaction.