Answer-to-Question-_1_

To: Agent of Developing Country
From: Tax Advisor
Subject: Setting up a petroleum fiscal regime in Developing Country

Dear Agent of Developing Country,

Thank you for reaching out to me with regard to setting up a petroleum fiscal regime that would address the newly discovered oil and gas resources in your jurisdiction.

I understand that this is a good opportunity for Developing Country to increase its revenues by raising tax income from this new business are, while at the same time not deterring potential corporate investments due to an excessive tax burden.

I will structure my response in two sectios: firstly, I will present of overview of different types of petroleum fiscal regimes and fiscal instruments available to governments for oil and gas taxation; and secondly, I will present potential recommendations that your jurisdiction might take into account towards setting up a petroleum fiscal regime.

1) Overview of petroleum fiscal regimes

In general, petroleum fiscal regimes may be classified as either 'Proprietorial' or 'Non-Proprietorial'.

Under **Proprietorial governance** of energy resources, the government acts as a typical landlord, seeking to earn a 'rent' for allowing access to the natural resources of its jurisdiction. This type of approach to oil and gas taxation does not concern itself with the profitability of oil and gas companies operating in the jurisdiction, and typically involves tax levied on cash flows/ revenues or on production volumes (e.g. tons of oil equivalent).

The most straightforward tool under Proprietorial governance is represented by **royalties**. These are either charged as a percentage of revenues earned by the oil and gas companies from the energy resources extracted in that jurisdiction, or it may take the form of a flat monetary value per unit of extracted resource (oil, gas etc.) Royalties are due irrespective of the profitability of the oil and gas company from its activity in that jurisdiction.

Another approach under a Proprietorial regime is a **tax on revenues/ cash flows** earned by the oil and gas company from the sale of respective energy resources. A good example of this is the Petroleum Revenue Tax (PRT) introduced by the UK in 1975 (as described by Hafez Abdo in "Taxation of UK Oil and Gas Production", hereinafter Abdo 2010). This revenue tax was also ring-fenced for each oil field (i.e. losses from one field cannot be used to ofset profits in another field), but allowed for the deduction of toyalties, an alloance for a certain quantity of oil that was not subject to tax, an uplift (enhancement of actual costs) for capital expenditure etc. PRT also does not take into account the actual profitability of the oil and gas companies.

Conversely, under **Non-Proprietorial governance**, governments act in a manner in which they accept some degree of responsibility for the profitability of the taxpayers operating in the oil and gas sector. Under such a fiscal regime, taxation is typically based on profits instead of on revenues or on production volumes.

The typical element of such a regime is **corporation tax** (i.e. corporate income tax), which is a tax on profits, allowing for deductions of all relevant, business related expenses incurred by the taxpayer. Naturally, corporation tax is not limited to Non-Proprietorial regimes, as this is a common instrument for governments to raise tax income.

Profit Sharing Contracts (PSCs) may be another approach of Non-Proprietorial regimes. Under a PSC, the oil and gas company is entitled to recoup its costs with the exploration, drilling and extraction, in the for of 'cost oil', after which the excess amounts of resources extracted are seen as 'profit oil'. Subsequently, profit oil is split between the government and the oil and gas company.

2)Recommendations for Developing Country

Given that Developing Country has no prior experience of an oil and gas fiscal regime, a Proprietorial approach to petroleum taxation seems more appropriate.

As Abdo 2010 has found, the UK has gradually shifted from a Proprietorial regime (1964 up to roughly 1983) to a Non-Proprietorial regim (from 1983 onwards), with the effect of petroleum tax income dropping sharply for the UK government, despite increasing oil prices for the period of e.g. 2005-2007.

As such, Abdo 2010 contends that the Non-Proprietorial approach of the UK was clearly not successful and that fiscal relaxation aimed at increasing production and expecting an increase in the tax revenues is an approach that lacks substance.

Therefore, given all the above points, Developing Country should probably look into setting up a **royalty regime** for oil and gas, as well as a **revenue tax** on sales of petroleum. Ring-fencing is also highly advisable, coupled with potential VAT exemptions for the exploration phase.

Setting up the exact royalty rate (or rates) and of a petroleum revenue tax will require actual projections of potential production of oil and gas, as well as potential revenues to be earned by oil and gas companies, which exceeds the scope of this exercise.

I hope you find the above useful.

Thank you and regards,
A Tax Advisor

Answer-to-Question-_2_

Where a Multinational Enterprise (MNE) has presence in several jurisdictions, transfer pricing rules become relevant (as a side note, transfer pricing applies for national groups as well, but the more simple case of only one jurisdiction is easier to manage for both tax authorities and taxpayers).

Whenver transactions occur between different entites of an MNE (the prices of which are called "transfer prices"), there is a risk that the entities will seek to gain undue tax advatages by setting the prices in such a way that reduces the overall tax exposure of the MNE as a whole (e.g. accumulating profits in low-tax jurisdictions or tax havens and accumulating expenses/ losses in high-tax jurisdiction). As such, transfer pricing rules have been adopted by most jurisdictions, in line with the observance of the Arm's Lengthe Principle (ALP, as set out in Article 9 of the OECD Model Tax Convention) and typically following the OECD Transfer Pricing Guidelines for Multinational Enterprises and Tax Administrations (OECD TPG).

While the transfer pricing rules (as set out by domestic legislation), as well as the guidance of the OECD TPG apply to any MNE, the particular types of intercompany transactions that may be encountered in the specific case of an energy MNE are outlined below.

1) **Sale of goods** - e.g. natural gas, petroleum, refinery products

etc.

It may be the case that energy resources extracted in Jurisdiction A by Company A part of an MNE are sold to Company B, part of the same MNE, resident in Jurisdiction B. Therefore, in order to ensure that the prices are arm's length, several public quotations for commodities are available (e.g. Brent oil price etc.), such that an external CUP may typically be available for such commodities.

In addition, it may be the case that either Company A also sells the same type of goods to third parties (i.e. not part of the MNE), or that Company B purchases the same type of goods from third-party suppliers. In such cases, internal CUPs (comparable uncontrolled prices) may be available, in order to document the observance of the ALP.

2) **Provision of services** - e.g. technical services (seismic studies, oil well modelling etc.) as well as more typical corporate services (e.g. accounting, HR, treasury, IT etc.)

Where intercompany services are provided, the main issues to take into account are deductibilty and arm's length pricing.

Typically, in order for deduction of services fees to be allowed for corporate tax purposes, the services should: (i) be effectively provided (i.e. an invoice is not enough, there must be evidence of actual activities carried out by the service provider); (ii) not duplicated (the intercompany services should not duplicate activities that are carried out in-house by the recipient or other services received from third parties); (iii) not be mere incidental benefits (where a company part of an MNE simply derives a benefit of being part of that MNE, but where no actual services is being provided); and (iv) bring a real economic or commercial benefit to the service recipient (this should be documented on a case-by case basis and is not necesarily connected to earning more revenues).

After these preliminary conditions have been established, the second relevant aspect is arm's length pricing. Services are typically charged under a cost-plus mechanism. For this reason, both the cost base and the mark-up applied are relevant from a transfer pricing perspective. The cost base should be constructed based on appropriate allocation of cost items (direct allocation wherever possible, and adequate allocation keys for indirect allocation, where direct allocation is not an option) and only those elements directly related to the provision of services should be included in the cost base.

Finally, an arm's length mark-up may be established either under the simplified approach (for routine services), where a 5% mark-up is deemed appropriate, or by carrying out a comparability study, in order to identify an arm's length range.

3) **Royalties for intellectual property (IP)**

It may be the case that certain IP elements are made available between entities of an MNE (such as patents, processes, trademarks, technology etc.), whereby a royalty fee is charged by the owner of the IP.

These cases may be covered by the application of the CUP method (using either external or internal comparables), taking into account the type of IP, the rights that are given to the licensee and the potential economic benefits that the licensee may reasonably expect.

4) **Leases**

Energy MNEs may resort to intercompany leases of equipment, where e.g. an entity of the MNE acquires the expensive equipment and then leases it out to related parties.

The reasonableness of the pricing (and compliance with the ALP) may be documented either using the CUP method (if suitable comparables are available), or by a transactional method (e.g. the TNMM), testing the results of the lessor against an arm's length range.

5) **Intercompany financing, financial guarantees, environmental guarantees:** these types of transactions may be significant for energy MNEs, as this field is typically capital intensive and intercompany financing or guarantees may be required. The main issues here are to ensure arm's length pricing (e.g. using the CUP method), as well as not running afoul of thin capitalisation rules in the jurisdiction of the borrower.

The main challenges that an MNE operating in the energy sector faces with regards to transfer pricing mainly refer to harmonizing the observance of transfer pricing rules with the other forms of taxation specific to the energy sector. Therefore, energy MNEs should carefully monitor the fiscal regimes specifically relating to their field, in each of the jurisdictions where they have a presence, and decide how best to approach operations (e.g. setting up a branch vs. a subsidiary, types of transactions that are reasonably carried out with third parties instead of related parties, residence of group service providers, procurement entities, treasury entities or lease entities etc.)

Answer-to-Question-_4_

The definition of a Permanenet Establishment (PE) is given by Article 5 of the OECD Model Tax Convention: "*a fixed place of business through which the business of an enterprise is wholly or partly carried out*" (Article 5 para. 1).

In the case of exploration and drilling activities, it is reasonable to expect that a non-resident entity carrying out such activities will have a presence, presumably in the form of a mine/ oil field site/ place of extraction of natural resources, as well as equipment and personnel.

Assuming the "fixed place of business" criterion is met, it is likely that such activities will be deemed to give rise to PE in the respective jurisdiction, which will be subject to tax.

An enterprise may decide to carry out exploration and drilling activities by relying on resident subcontractors, operating in their regular course of busines (Article 5 para. 6). However, if the respective subcontractors act only at the specific instructions of the non-resident enterprise, carrying out services on its behalf and with the respective enterprise being its only client, the definition of dependent agent may be triggered and as such the non-resident enterprise may be found to have a PE in the respective jurisdiction (Article 5 para. 5).

A solution to this situation is for the enterprise to setup subsidiaries in each of the jurisdictions where it carries out exploration and drilling activities, as such avoiding PE status, with only those respective subsidiaries being subject to tax in their jurisdiction of residence (and not the parent entity).

Where the enterprise is deemed to have a PE, the profits of that PE are subject to tax in the jurisdiction where the PE is located as described under Article 7 of the OECD Model Tax Convention ("Business profits") - or the relevant article of a specific double tax treaty.

A PE may be required to keep accounting records and to file relevant tax returns in the jurisdiction where it is located and subject to tax, thus raising compliance issues for the head office.

Answer-to-Question-_5_

Decommissioning of oil and gas assets is typically expensive to carry out and the respective expense is deductible only during the period where it is actually incurred (i.e. when the actual decommissioning is carried out).

Oil and gas companies may be required by accounting regulations to constitute provisions during each financial exercise, accounting for the respective apportioned yearly value of the future envisaged decommissioning costs. However, these provisions are typically non-deductible for corporate tax purposes, deduction only being allowed in the financial exercise when the decommissioning is carried out and the costs are incurred. This may have a significant impact on the tax position of the oil and gas company, increasing its tax base and potentially attracting additional corporate tax being levied against it.

Some jurisdictions allow oil and gas companies to make payments into a decommissioning fund, which are not seen as deposits/ guarantees, but rather as irrecoverable contributions towards to future decommissioning. These payments are typically deductible for corporate tax purposes.

In addition, decommissioning expenses may be capitalized and depreciated during the useful life of the oil and gas installation (effectively increasing the book value of the assets with the value of the decommissiong costs that will be incurred

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10 or 20 years down the line). Depreciation is typically deductible for corporate tax purposes.

Naturally, these different scenarios have different implications for oil and gas companies, with the most likely effect of increasing the tax liabilities of the companies during the period of operation of the oil and gas installations. Coversely, from the perspective of governments aiming to achieve a transition to net zero, it may be worthwile to offer tax incentives to oil and gas companies in order to get them to decommission the oil and gas installations sooner rather than later (assuming that the respective companies will also shift their business focus to renewables or other business activities). As such, governments may decide to allow companies to deduct provisions for decommissiong expenses each year, in order to decrease the tax impact during the useful life of the installation.

Answer-to-Question-_7_

The decision between debt and equity when financing a business is generally relevant for all industries, and is not exclusive to the energy sector.

Financing using equity instruments has the advantage of allowing the respective company more flexibility to enter various projects and the freedom to acquire debt at a later stage, without the risk of being overleveraged and without needing to incur significant interest expenses. A potential disadvantage under this approach is that profits repatriation (in case of non-resident parent entities) is done via dividends, which are distributed from profits after tax, and may also be subject to withhoding tax in the source jurisdiction (i.e. that of the payor). In addition, dividends do not lower the tax base for corporate tax purposes (as opposed, potentially, to interest expense).

Conversely, financing using debt instruments has the main advantage of being able to claim deductions for the interest expense for corporate tax purposes, with a potential disadvantage being that there is less flexibility to take on new debt as needed to engage in new projects, as well as potential covenants and guarantees imposed by the lender.

In this context, thin capitalization rules ("thin cap") are aimed to prevent a company from relying excessively on debt financing, by disallowing the deductibility of interest expense once certain thresholds are exceeded. Thin cap may either refer to an economic or financial ratio (e.g. debt-to-equity), (e.g. for debt to equity ratios higher than 3-to-1, all interest expense is non-deductible for corporate tax purposes), or to interest expense as a percentage of EBITDA (earnings before interest, tax, depreciation and amortization) - e.g. interest expense that exceeds 30% of EBITDA is non-deductible for corporate tax purposes.

The role of thin cap rules is two-fold: firstly, to avoid the unreasonable erosion of the corporate tax base using interest expense, and secondly to ensure that companies have no incentives to become overleveraged, which would be threatening them as ongoing concerns.

Therefore, when assessing project economics and an optimal mix of debt and equity, thin cap rules must always be taken into account, ensuring that overleveraging does not increase the corporate tax liabilities of the company. In addition, excesive levels of debt may affect the creditworthines of the respective entity, hence potentially triggering higher interest rates when attempting to acquire additional debt. An optimal debt-to-equity mix would presumably not run afoul of thin cap rules and allow enough flexibility for the company going forward.