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In this issue

Global oil & gas tax newsletter

Views from around the world

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Editor's introduction

Bill Page, Deloitte UK

Welcome to the third edition of the Global Oil and Gas Tax Newsletter for 2017.

The Organization for Cooperation and Economic Development's (OECD) base erosion and profit shifting (BEPS) initiative is now a recurrent theme in this publication. This is not surprising since BEPS represents the most significant change in international taxation for a generation. In this issue, we focus on two specific areas affecting the oil and gas industry. Our Global Tax leader for oil and gas, Chris Roberge, comments on the implications of BEPS Action 7, which addresses permanent establishments, for the industry and I provide comments on the long-awaited draft toolkit on offshore indirect transfers of assets. While this is not one of the 15 BEPS actions, the G20 asked the OECD and other bodies develop the toolkit to help developing countries prepare legislation to tax such transactions. This has been a contentious issue for the extractives industries for several years, and the toolkit seems unlikely to change that situation.

In the remainder of the newsletter, we look at:

- Changing approaches to managing rotator populations in the light of an oil price that is likely to remain "lower for longer."
- The latest VAT developments affecting the industry in the Persian Gulf region
- The implications of changes to accounting rules applicable in the member states of OHADA (Organization for the Harmonization of Corporate Law in Africa), which covers Francophone Africa
- Recent changes to the tax regime in Indonesia intended to encourage new investment in upstream projects
- A reminder of the scope of withholding tax applicable in South Africa to industry participants as the country prepares for an expansion of upstream activity.
- Proposed changes to the Swiss tax regime for commodity traders to align with the BEPS actions

Our next issue will be released in March 2018. As always, I welcome comments and suggestions from readers, and may be contacted at bpage@deloitte.co.uk.

Best wishes for the holiday period and 2018.

BEPS Action 7: Implications of the revised permanent establishment definition to oil and gas companies

Christopher Roberge and Marc-Andre Marchand, Deloitte China

International centers of excellence

During the summer of 2017, representatives of more than 70 jurisdictions signed the Multilateral Convention to Implement Tax Treaty Related Measures to Prevent Base Erosion and Profit Shifting (MLI) in order to implement measures arising from the BEPS project. Subject to any specific country reservations, BEPS Action 2 (hybrid mismatches), Action 6 (treaty abuse) Action 7 (permanent establishments), and Action 14 (mutual agreement procedures) are included in the MLI.

BEPS Action 7 focuses on broadening the circumstances under which a person (including a corporation) could create a taxable presence in a foreign jurisdiction. For oil and gas companies located in the jurisdictions that have opted to introduce Action 7, permanent establishment (PE) provisions, the impact of the modified definition of PE could be significant, and a careful review of corporate activities should be undertaken. This article outlines the effect of BEPS Action 7 on the oil and gas sector and its application on some key industry activities.

Modified definition of PE

BEPS Action 7 modifies Article 5 of the OECD model tax treaty, but the basic principles generally remain the same. A PE could still be created in one of three ways: (1) an agency PE; (2) a fixed place of business PE; or (3) a construction site PE. It should be noted that, prior to the review of the application of a specific tax treaty, it must be determined whether there is a taxation right under the relevant country's domestic law.

01. Generally, an agency PE is created when an agent located in a foreign jurisdiction concludes contracts on behalf of a corporation (its principal). Prior to Action 7, no PE was created where the agent was considered to be independent from the principal, such as a broker or a commissioner acting in the ordinary course of its business. Under the new framework, the independent agent exception would have a narrower application, and an agent generally would not be considered independent if it was working solely for one group of companies. Furthermore, the agency PE definition would be broader, and a PE is created where the agent habitually plays a leading role in the conclusion of contracts on behalf of the principal.

02. A PE also can be triggered where a foreign entity maintains a fixed place of business in another country. Historically, the OECD model tax treaty provided exemptions, such that a PE would not arise where a corporation was carrying on certain specific activities—including the maintaining of stock for the storage or display of goods in a foreign jurisdiction. In the past, multinationals tended to rely on the exemptions in structuring their supply chains.

    Going forward, however, to qualify for the exemptions to a fixed place of business PE, the overall activities in a foreign jurisdiction would need to be considered solely preparatory or auxiliary to the business as a whole (considering both the enterprise itself and the closely related enterprise(s) carrying on business activities at the same place, or at another place in the same jurisdiction). Where this is not the case, it is likely a PE will be created.

03. A construction site or installation project located in a foreign jurisdiction that lasts for more than 12 months can also create a PE. Prior to Action 7, one strategy used to avoid the creation of such a PE was to split construction contracts between related enterprises so that the 12-month threshold would not be met by any company individually. Under the new framework, this strategy could be subject to specific anti-abuse rules.

Application to the oil and gas sector

Commodity trading activities and service companies

It is common for a subsidiary of a corporate group operating in the oil and gas sector to act as a commodity trading agent and play an active role in negotiating commodity contacts on behalf of a principal located in a foreign jurisdiction. In some cases, the parent corporation may play this role on behalf of its subsidiaries. This type of arrangement would likely need to be revisited under the new framework. More specifically, where commodity trading activities are carried on, such that the leading role in negotiation is located abroad and the contracts are routinely concluded without material modification by the principal, PE exposure would arise in the foreign country where the negotiation took place.

Similarly, given the integrated nature of many oil and gas services companies, PEs may be created in a foreign jurisdiction by effectively concluding contracts through material negotiation on behalf of a principal located elsewhere.

It is, therefore, important to determine which entity habitually concludes contracts or habitually plays a leading role in the negotiation. For commodity trading, companies will need to carefully review how contracts are negotiated and by whom. It is expected that many countries will seek to utilize this provision to draw energy trading profits into their jurisdiction and away from the country of operations of the trader. Similarly, for oilfield services companies, sales of products, supplies, and technology could be the subject of a PE debate due to the involvement of the local country entity in concluding sales contracts.

In all cases, a review of the relevant supply chain is recommended to mitigate risks of lengthy tax audits and resulting additional tax assessments—and even litigation.

Storage of oil and gas

Upstream or downstream oil and gas companies often use overseas storage facilities to stock supplies. Prior to the implementation of Action 7, a storage facility located abroad is unlikely to have given rise to a PE since the stock of supplies could have fallen into the specific activities exemptions. Under the new framework, PE exposure is created unless the stock is proved to be held as part of preparatory or auxiliary activities of the business or closely related enterprise(s) carrying on business activities at the same place, or at another place in the same jurisdiction. Based on the draft contents of the 2017 update to the OECD model treaty, the term "preparatory activities" refers to those activities performed in contemplation of carrying on what normally would constitute the essential and significant part of a business as a whole. Auxiliary activities are those carried on in support of an enterprise as a whole (without being an essential and significant part of the activity).

As a result of Action 7, an activity such as the storage of crude oil could create different PE outcomes. In particular, companies will need to define what is preparatory or auxiliary to their business. This may not be easy for integrated groups and may be difficult to explain to tax authorities with little industry experience. For example, an upstream oil and gas company could store crude oil prior to sale and shipment to a refiner. This activity could be considered an auxiliary part of the company's business and, therefore, might not create a PE. However, a different outcome could arise where a trading company keeps crude oil stock in a certain jurisdiction to ensure proximity to its customers or simply holds the stock to speculate on the future oil price. In this case, the tax authorities might argue that the storage of crude oil is not auxiliary, but rather part of the oil trading business as a whole, which would create a PE.

Construction sites
Upstream oil and gas projects usually require preliminary construction activities. Action 7 does not modify the construction site exemption under Article 5 of the OECD tax treaty. Rather, the perceived abuses with respect to the construction PE definition are addressed by the application of various BEPS anti-abuse rules. The specific scenarios targeted are construction contracts (related to the same project or building) that are divided, such that no contract would last more than 12 months, consequently avoiding creating a PE. As a result of implementation of Action 7, all activities of closely related enterprises, with respect to the same project or construction site, will be considered in the aggregate for purposes of calculating the 12-month period. This also may impact activities carried out on the relevant country's continental shelf. Further, it is possible that a PE could be created inadvertently. In a large field development project, a wide range of skills and expertise is needed, and, for many logical non-tax reasons, these skills exist in various subsidiaries of a group. Moreover, it is common for a head office to send staff overseas, such as geologists or engineers, to supervise or undertake various types of preliminary activities on behalf of the principal. Traditionally, these costs would be charged from the head office to the local legal entity located overseas. If a construction PE is created, profit could be attributed to the PE and compliance requirements may be triggered. Groups should be aware that tax authorities may seek to group these contracts together and deem a PE in respect of the aggregated activities.

The changes to the PE rules make it likely that more construction PEs will be created, resulting in an increase in taxation and filing obligations.

What's next?
Creating a PE would have two major consequences, one being the tax compliance required in the specific jurisdiction and the other the attribution of profit to the PE. The OECD is currently reviewing comments received on the discussion draft on the attribution of profits to a PE, and companies should monitor these developments closely.

Ratification of the MLI by the signatory countries is expected to be completed within the next two to three years. Once the MLI has been implemented by relevant jurisdictions, tax treaty provisions will need to be read in conjunction with the corresponding provisions of the MLI and along with any related country reservations. Subject to the specific country reservation, Action 7 could have major repercussions on the current oil and gas business model, so now is the time to plan accordingly.

Taxation of offshore indirect transfers of assets

Bill Page, Deloitte UK

On August 1, 2017, the Platform for Collaboration on Tax (the Platform) issued a discussion draft of its toolkit to assist low-income (i.e., developing) countries to address the challenges of taxing gains on offshore indirect transfers of assets (abbreviated to OITs in the draft). The Platform is a joint initiative of the International Monetary Fund (IMF), OECD, United Nations (UN) and the World Bank set up in response to the BEPS initiative. The issue of OITs is not part of the 15 BEPS Actions, but was highlighted as a critical area in the two-part report on the impact of BEPS on low-income countries prepared for the OECD for the G20's Development Working Group in 2014 (see our September 2016 edition for a detailed discussion). The 2014 report recommended the preparation of toolkits to address various BEPS issues faced by low-income countries and the subject of this article is one of the most anticipated. Comments were invited on the draft before October 20, 2017, and a final version of the toolkit is expected by the end of 2017.

While many mature economies have long-established legislation taxing OITs, there have been several well-publicized tax disputes over OITs of oil and gas and other valuable assets located in emerging markets over the past decade. Many of these remain unresolved. Typically these have involved disposals of shares in a special purpose entity (SPE) established in a low-tax jurisdiction. SPE owns, directly or via a subsidiary, a valuable asset in jurisdiction X. The assets concerned have been mainly upstream oil and gas projects or mines, but there also have been a number of cases involving other assets, such as telecommunication licenses. While the tax rules in jurisdiction X would tax a gain arising on a direct sale of the asset itself, the sale of the SPE is argued to be nontaxable, either on the grounds that domestic law does not tax such gains or because jurisdiction X has agreed not to apply its taxing right under an applicable tax treaty. Responses to such arguments have included law changes (including some with retroactive effect) and the renegotiation of treaties. Tax authorities in some jurisdictions have argued that general anti-abuse principles enable them to tax the sale since, in substance, there has been a disposal of the underlying asset rather than a sale of the shares in the SPE. More complex transactions involving multiple jurisdictions and stock market transactions also have been challenged, as have group reorganizations that did not generate economic gains. In the upstream oil and gas industry, the common requirement for government consent to the direct or indirect change of control of a production-sharing contract or concession agreement has been employed as a lever to compel payment of tax in cases where the tax laws themselves may not be clear.

General comments

One of the most important messages of the toolkit is included in the executive summary:

"There is a need for a more uniform approach to the taxation of OITs. Countries' unilateral responses have differed widely, in terms both which assets are covered and the legal approach taken. Greater coherence could help secure tax revenue and enhance tax certainty."

Tax certainty is particularly important for companies in the extractive industries because of the large investments required and the long lives of projects. Whether the toolkit achieves this, however, will depend on the extent to which low-income countries follow the guidance presented in the final version. This may not be helped by the fact that the draft contains two quite different approaches for countries to consider. Moreover it should be noted that many countries have already introduced legislation (some of it specifically targeted at the extractive industries) and may be reluctant to change their tax laws, even after the toolkit is finalized.

Structure of the draft toolkit

- The anatomy of offshore indirect transfers provides an example of a generic OIT structure, similar to that outlined above. It then introduces some of the key issues that will be important in the remainder of the document, such as the potential impact of tax treaties, concepts of immovable property and location-specific rents (discussed further below). It also considers (and rejects) the arguments for not taxing gains at all.

- How taxing rights on OITs should be allocated addresses the issue of whether the primary taxing rights should rest with the country where the asset is located or with the location of the actual seller, and which assets should be covered. It concludes that the rights to tax OITs should rest with the country where the assets are located in the case of assets generating location-specific rents.

- Three illustrative examples look at the specifics of well-known cases involving assets in India, Peru, and Uganda, emphasizing the material amounts involved and the risk that resulting political pressures may result in "more incoherence and uncertainty in international taxation than already exists, for no apparent gain."

- Tax treaties and offshore indirect transfers looks at the relevant provisions of the OECD and UN model tax treaties, how they are evolving, and how they are adopted in practice. It also considers the extent to which the adoption of the Multilateral Convention to Implement Treaty Related Measures to Prevent Base Erosion and Profit Shifting (MLI) provides a mechanism to close loopholes created by current tax treaties.

- Implementation challenges and options sets out two models for implementing domestic legislation to tax OITs (taxation of a deemed disposal, or extension of the source rule to certain share transactions), including recommendations on how these could be drafted.

- The conclusions provide a summary of the key recommendations: 1) Gains derived from certain categories of assets should be taxed in the source country; 2) A more uniform approach to taxing these is required; and 3) The preferred approach is to tax OITs as a deemed disposal of the underlying asset.

- The appendices provide a placeholder for the comments expected in the consultation period, examples of specific country rules from China, Peru, and the US, and the results of an analysis of tax treaty provisions regarding the allocation of taxing rights between the country of residence of the seller and the country where the relevant asset is located.

The remainder of this article offers a more detailed analysis of key aspects of the draft toolkit and some of the open issues that will be addressed in the final version scheduled to be released at the end of 2017.

General

Not surprisingly, the toolkit is very focused on the potential for companies to use OITs to avoid taxation. In doing so, it creates the impression that the toolkit authors view all investment structuring as motivated by a desire to avoid tax and all OITs as abusive. Investment structures can be influenced by many other factors, including the following:

- Meeting requirements for raising equity, or project and other types of financing

- The fact that investments in a particular region are often held and managed from regional hubs with good infrastructure and communications facilities

- A need for access to bilateral investment treaties—particularly for natural resource projects—to protect long-term investments against more aggressive forms of resource nationalism

The sale of a company owning an asset may be preferred by a buyer and seller since it preserves all existing licenses, permits and third-party contracts for sales and purchases that a company has entered into—which will minimize the impact on day-to-day operations and risk of loss of value. Preservation of such nontax attributes may result in an OIT being favored over a direct sale of underlying assets, regardless of tax considerations.

Should capital gains on OITs be taxed?

The toolkit includes a discussion of the rationale for taxing gains on OITs and provides two apparently contradictory reasons:

01. It is argued that because an acquirer takes into account the taxation of future revenue to be generated by an asset it is acquiring, any gain realized by the seller must reflect "changes in earnings that would otherwise be untaxed." The justification for this statement seems to be the subsequent statement that, "…the exploitation of avoidance opportunities may diminish the effective power of the country in which the underlying assets are located to tax future earnings…" These assertions are not substantiated in the draft and seem to focus unduly on tax minimization as a motivator of business behavior. This neglects the fact that buyers and sellers always will have differing views on the value of any asset to their future business, independent of tax considerations. For example, a mature oil field may be deemed noncore by a major focusing on gas, while it may be desirable for a startup funded by private equity, regardless of any specific tax attributes of the asset or differences in the tax positions of the buyer and seller.

02. On the other hand, the draft toolkit states that, provided the purchaser receives a step-up in basis, the impact of taxation is expected to be neutral, which ignores timing effects, since the purchaser will be able to deduct the purchase price from future revenues. On this basis, the reason for imposing tax on any gain is to realize a timing benefit for the host government, which is potentially valuable to a low-income country that may have difficulty in raising finance from other sources (such as taxation of the domestic economy or borrowing). This does not fully acknowledge the difference between a share purchase (where the purchaser would only be able to offset the cost against a future sale which may not happen) and a purchase of the underlying asset (where a step-up in basis would often, but not always, be given for tax depreciation).

There are good arguments against imposing taxes on OITs, which include the fact that disposals do not affect the country's overall share of location-specific rents, and that taxing them heavily may inhibit transfers of assets to those most willing and able to develop and operate them. Regardless of how one views the arguments for taxing OITs, however, given the attention focused on this issue, and the significant pressure on budgets in developing countries (particularly those with large upstream hydrocarbon and/or mining sectors), it seems unlikely that the rationale for taxing OITs will be debated very long by policymakers. As noted above, many countries have already introduced legislation to capture tax on such transactions.

Which capital gains should be included and which country should have primary taxing rights?

The draft toolkit points out that it is well established that countries where immovable assets are located should have the primary right to tax gains derived from those assets and that this is reflected in both the OECD and UN model treaties. It is argued that it is reasonable for location countries to tax OITs on the grounds that the distribution of profits derived from the assets is taxed in the location country via withholding tax or branch remittance taxes.

Definitions of immovable property or assets commonly include real estate and rights to the exploration and exploitation of natural resources, so the oil and gas industry is affected already. The toolkit proposes to expand the definition of immovable property under the domestic tax law of the country in question to include all assets generating location- specific rents. These are defined as economic returns in excess of the minimum normal level of return that an investor requires—rents that are uniquely associated with some specific location, and can thus be taxed without, in theory, having any effect on the extent or location of the underlying activity or asset. The examples provided include other kinds of rights or licenses provided by governments (such as telecommunication networks and broadcast spectrum) and rights to operate regulated industries. The toolkit authors also suggest that further consideration is required to craft an appropriate legal definition.

The draft toolkit briefly addresses the question of whether some part of OITs might be attributable to increases in value created by management and technical expertise provided by the parent company. While this argument is considered to have some merit, the point is made that, in most cases, the SPE making the sale will have little function other than as a holding company, and relevant expertise is likely to lie elsewhere in larger groups. This is not considered a compelling argument against primary taxing rights being allocated to the country where the relevant assets are located. There is an argument that any increase in value attributable to significant people functions located elsewhere in a separate entity should be remunerated on an arm's-length basis in line with the overall approach of the BEPS initiative. A windfall gain realized on an OIT, therefore, might suggest that some kind of success fee should be attributed to the service provider and deducted against the gain in determining the tax liability.

How should domestic law tax gains?

The draft toolkit provides two models (as well as commentary and examples of legislation) for imposing taxes on OITs, and both are based on existing practice. It also considers an anti-avoidance rule as an alternative approach, as is used in China. The anti-avoidance approach is not recommended for several reasons—which practice would suggest are sensible: Drafting an anti-abuse rule is challenging and often may require the exercise of significant discretion by the tax authorities; capacity constraints mean it may be difficult for tax authorities to apply the rule in a predictable way; and it would be necessary for tax authorities to demonstrate a tax avoidance motive to justify application, which may be difficult in practice.

Model 1 is the preferred approach in the draft toolkit on the basis that it arguably is easier to enforce and simpler to apply. It contemplates that the entity located in the relevant jurisdiction is to be treated as disposing, and immediately reacquiring, at market value, all of its assets and liabilities. The proposed provisions trigger the deemed disposal where the underlying ownership of the entity changes by more than 50 percent as compared to that ownership at any time in the preceding three years. An entity would fall within the scope of the provisions if it directly or indirectly derives (or has derived in the preceding 365 days) more than 50 percent of its value from immovable property in the country. There is no specific definition of "an entity" for these purposes, but it seems to include a foreign legal entity, as well as a tax resident local subsidiary. It seems that it is not the intention to tax foreign legal entities on a deemed disposal of assets and liabilities in other jurisdictions. However, this is not explicit and could be a problem in some jurisdictions where the approach to taxing foreign legal entities may not be clear-cut in law or practice.

It is clearly important that domestic law provides a clear definition of "underlying ownership," although this is not offered in the draft. The intention seems to be to link this to the ownership of the ultimate parent company, which could conceivably give rise to the triggering of deemed disposals as a result of normal trading, given the three-year window, and would certainly do so in the case of a takeover of a listed entity. However, an automatic exemption would appear to apply to corporate reorganizations that do not give rise to a change in the ultimate owner. Experience suggests that a more extensive definition of underlying ownership will be needed given the broad definition of interests and entities suggested. The definition may also need to address rights to acquire shares under certain circumstances as commonly found in shareholder agreements.

Notably, the deemed disposal applies to all assets and liabilities, not just the immovable asset(s) deriving location specific rents. This is an all or nothing approach—until the threshold (i.e., a change of more than 50 percent) is reached, there are no deemed disposals. Once that is exceeded, everything is treated as sold and reacquired. This approach will lead to taxation that is disproportionate to actual economic gains and would, for example, penalize a minority investor in a joint-venture entity, where the majority owner is subject to a takeover by a third party. It should be remembered that the entity, not having made an actual sale, will not have generated cash to pay any tax considered to be due. Presumably the buyer (rather than the seller which realized the gain) would be expected to fund the taxpayer's settlement of obligations, absent a specific funding contractual mechanism (e.g., the share sale and purchase agreement).

A further drawback to this approach, as drafted, is that it does not provide any obvious method for relief from double taxation if the actual seller is subject to tax on the real gain that it realizes since the tax triggered is payable by a different entity.

If Model 1 is adopted, it would be important to ensure that legislation clearly provides for a consequent step-up (or step-down) in tax basis of the assets and liabilities deemed to be sold and reacquired, including basis for future tax depreciation. This is assumed by the toolkit, but our experience of working with fiscal policy and tax authorities in developing countries suggests it should be flagged more prominently as a requirement to ensure a reasonable tax result. It is also important to consider the specifics of tax depreciation used in the relevant jurisdiction. For example, in a pooling mechanism the tax depreciated value at the start of the tax period is increased by new expenditure, and disposal proceeds deducted from the total will prima facie not give rise to any tax liability as the deemed proceeds and deemed cost of reacquisition simply cancel each other out. Clearly, this is not the intention. Further, the original capital expenditure on the asset in the case of an oil and gas project usually would represent costs of drilling, field facilities, pipelines, etc., and the depreciation treatment for second-hand expenditures may be different, which could have a significant impact on project economics if the depreciation schedule is altered as a result of a deemed sale and reacquisition.

Actual disposals of assets may give rise to transaction taxes (e.g., stamp duty) and indirect taxes (e.g., VAT), as well as taxes on the repatriation of profits (via WHT on dividends or branch remittance tax). The draft toolkit does not mention any of these taxes, so it is not clear how they would be applied in the case of a deemed disposal.

However, the draft does mention the importance of amending source rules to exclude taxation of the disposal of the shares or other interests in addition to the deemed disposal. This is a key issue in practice (for example, Tanzania's source rules will potentially tax the direct sale of a local subsidiary and, at the same time, apply change-of-control provisions to deem a disposal and reacquisition of that entity's assets and liabilities at market value).

Model 2 in the draft toolkit relies on changing the country's source rule to tax gains arising from OITs in the hands of the actual seller of the relevant interest (shares or otherwise). Two approaches are set out. A simplified version suggests extending the country's source rules to gains on any shares or other interests deriving more than 50 percent of their value directly or indirectly from immovable property in the country (the approach taken by Canada). A more complex version adds a requirement that, in the case of shares or interests deriving more than 20 percent, but not more than 50 percent of their value directly or indirectly from such assets, a proportion of the gain should be taxed based on the ratio of the value derived from the immovable property in the country to the total value of the interest. While this provides some chance that tax would be proportionate to economic gains in the case of such disposals (although the gross value of assets in a jurisdiction is not necessarily indicative of any latent gain), under this model, tax would apply disproportionately in the case of shares and other interests that derive more than 50 percent of their value from assets in the country (though not at all if the value so derived is 20 percent or less of the total). This could result in double or triple economic taxation. For example, assume that company X holds interests in oil and gas fields in country Y and country Z. Sixty percent of the value of company X derives from the fields in Y and 40 percent from Z. In the event of a sale of X, if country Z has introduced the more complex version of Model 2, it is possible that the entire gain on the disposal will be taxed in country Y and 40 percent of the gain in country Z. This is a clear case of economic double taxation. If the gains also are taxed in X's home jurisdiction, triple taxation of some of the gain may arise, depending on whether and how the home jurisdiction relieves foreign tax.

The draft toolkit favors Model 1 over Model 2, as it is stated that Model 2 would require extensive enforcement and collection machinery, such as requiring the local entity to report changes in shareholdings and act as the agent for payment of any tax due. However, it is not clear that this is actually any more onerous than the reporting and payment obligations under Model 1. Regulations for the extractive industries usually impose reporting requirements for changes in the underlying ownership of oil and gas projects or mines, and there is an increasing tendency for OITs to require government consent in the same way as direct transfers. The requirements for reporting and consent provide levers to enable governments to compel the payment of taxes. It should also be remembered that given the significant costs, benefits, and lifespans of oil and gas projects, it is highly unusual for companies to attempt to avoid their tax obligations. This is because the costs of losing a social license to operate in a country, and the risk of adverse publicity significantly outweigh any supposed short-term advantage.

Alternatively, the draft suggests that the purchaser should be required to withhold tax at the time the sales price is paid, which might be offset against the final agreed liability. It also is suggested that a de minimis exemption be introduced for portfolio investments (where the total holding of the seller is less than 10 percent) or listed shares, and that an exemption may be provided for group reorganizations where the ultimate ownership does not change substantially.

The advantage of Model 2 for taxpayers is that it is the actual disposal that is taxed, rather than the deemed disposal contemplated by Model 1, so the ultimate liability should be linked to the economic gain actually realized (though not all of that would necessarily arise from the immovable assets). The major disadvantage for the purchaser is that the base cost of the shares would be available only to offset in the event of a future sale of the same shares. There would be no step-up in basis available for underlying assets, which is a potential attraction of Model 1 for purchasers. Of course, the option of a direct purchase of the asset itself could be pursued if that is a key value driver for the purchaser.

Both models potentially tax more than the actual gains arising in relation to the relevant immovable property. Model 1 deems the disposal of all assets and liabilities, not just the immovable property (though it seems likely that the bulk of any resulting gains would be contributed by the latter in most cases). It also does this in any case where more than 50 percent of the underlying ownership has changed; in other words, a taxpayer would pay tax on 100 percent of a latent gain, even if 49.99 percent of the underlying ownership of the assets has not changed. Model 2, on the other hand, would introduce an extraterritorial element of taxation; in any case, where more than 50 percent of the value of shares or other interests sold derives from immovable property in country X, all the gains on the sale would be taxable in country X, regardless of any gains deriving from other countries or from assets other than immovable property.

How should tax treaties address the taxation of gains?

The draft devotes considerable attention to a discussion of tax treaties. This may seem a bit odd to some readers, since developing countries frequently have limited treaty networks (e.g., Angola and Equatorial Guinea have no bilateral tax treaties in force at the time of writing), and the stated main purpose of the toolkit is to assist countries in drafting domestic laws to address OITs. The toolkit points out, however, that many treaties currently in force do not adequately protect resource-rich countries' taxing rights in the case of OITs, which is particularly concerning to the toolkit authors in the case of treaties with low tax jurisdictions (the Mauritius-Uganda treaty is cited). The statistical evidence supporting this assertion is presented in appendix 3. The toolkit recommends adoption of the MLI to implement treaty-related measures to prevent BEPS as a solution. Broadly, the MLI can incorporate the effect of Article 13.4 of the 2017 OECD model convention into a signatory's current treaties (if also adopted by the relevant counterparties). This provides as follows:

“Gains derived by a resident of a Contracting State from the alienation of shares or comparable interests, such as interests in a partnership or trust, may be taxed in the other Contracting State if, at any time during the 365 days preceding the alienation, these shares or comparable interests derived more than 50 percent of their value directly or indirectly from immovable property, as defined in Article 6, situated in that other State.”

This needs to be supported by adequate domestic legislation to be effective as a means of securing the right to tax OITs (see the discussion of Model 2 above). The language of Article 13.4 does not state that all that gains may be taxed, so it would be possible for domestic law to apply tax only to that portion of the gains arising in the relevant country from the relevant asset(s). Further, Article 13.4 does not provide a right to tax gains in cases where the value attributable to assets in the country lies in the 20–50 percent band contemplated by the more complex version of Model 2. Moreover, it does not address Model 1’s deemed disposal approach for taxing OITs.

Valuation and base cost

Valuation is fundamental to the successful application of both models. Model 1 requires the taxpayer to agree on market values for all assets and liabilities with the tax authorities. Model 2 requires agreement on the proportion of the value of shares and other interests deriving from assets in the relevant jurisdiction to determine whether to tax the gain, and in the case of the more complex version, how much of the gain may be taxed in certain circumstances. The draft does not address the question of how to value assets. While it is reasonable that the draft toolkit does not incorporate a comprehensive valuation manual, this is a contentious area in practice. For example, tax authorities in developing countries may have difficulty assessing the reasonableness of reserves estimates, production profiles, price forecasts, cost estimates (including decommissioning), discount rates and any adjustments to the pricing of comparable historic transactions needed to assess the rapid decline in hydrocarbon values since 2014. It also is unlikely that the authorities will have access to funding to hire third-party experts to carry out a valuation on their behalf. It would seem reasonable to include some reference to these sorts of complexities, the importance of using multiple methods to validate proposed values, differences between valuing assets and shares, and perhaps suggest additional resources that countries could utilize in arriving at realistic values, such as the secondment of experts from other jurisdictions under the Tax Inspectors without Borders initiative. Hopefully, this will be addressed in the final version of the toolkit.

Costs also are a potentially contentious issue. Model 1 relies on the application of the normal principles of domestic tax law, which should (at least in most cases) be reasonably well understood and tested. Model 2, however, would apply to transactions in shares and other interests that previously may not have been within the scope of the tax law. Consequently, issues such as the determination of base cost may not be so straightforward (e.g., the base cost of a share that was acquired via a share-for-share exchange or that has been subject to reinvestment relief in the jurisdiction where it is located).

Currency issues may be problematic; the currency in which the shares are denominated may not be the currency in which the gain is calculated and currency fluctuations could have a significant impact on the tax payable. Currency issues also may be an issue with Model 1 and with actual direct transfers of interests, but the extraterritorial nature of the charge under Model 2 strengthens the argument for using the relevant functional currency, rather than local currency.

Reorganizations and reinvestments

The draft toolkit mentions in several footnotes that OITs as part of reorganizations may be treated as tax-free, subject to the continuity of substantial underlying ownership. This is common in legislation and logical, given that a reorganization does not give rise to an economic gain. In the case of Model 1, tax liability would not be triggered where there is no underlying ownership of the relevant assets, so the relief should be automatic. On the other hand, the wording provided to implement

Model 2 does not provide any language to exempt such group reorganizations, even though these may be carried out for bona fide commercial reasons (e.g., to facilitate financing arrangements). This seems to be an important gap in the proposal, which hopefully will be addressed in the final version.

The draft does not address the provision of relief for the reinvestment of proceeds, although this too is often found in capital gains tax regimes with similar relief being provided for the noncash element of farm-in transactions. In the oil and gas industry, the holder of a license frequently will make a partial disposal of its interest in a project (directly or via an OIT) to generate proceeds to finance its obligations in relation to the retained interest. Oil and gas companies also manage and share risk by diluting their interests in larger or riskier projects. Imposing a tax cost on such behavior may inhibit transactions, which encourage investment and maximize the long-term benefits oil and gas projects bring to host countries. Where transactions do take place, it will reduce the funds available for future investment in the project with the same effect. Again, the hoped is that some form of relief will be suggested in the final version of the toolkit.

Transactions in listed stock and shares

The decision to acquire the shares of a listed entity is seldom, if ever, driven by a desire to mitigate tax, so it seems reasonable to exclude such transactions from the application of both models. The draft offers countries adopting Model 2 the option of excluding transactions in listed shares and suggests that certain transactions may be considered de minimis, for example, disposals of shares constituting in total less than 10 percent of the total issued share capital of the relevant entity. Arguably, these should be more strongly recommended. No similar exemptions are suggested for Model 1, though it is possible that the underlying ownership of an entity could change by more than 50 percent during a three-year period simply as a result of trading on the stock market, particularly in times of price volatility.

Sanctity of contract

Oil and gas projects in developing countries are usually subject to concessions, production sharing arrangements, and/or host government agreements. Given the long-term nature of projects and the significant investments required, governments often provide some protection against law changes that would impact the economic interest of the investor (e.g., by incorporating specific tax rules, applying legislation in effect at the date the agreement comes into effect, or providing a means to rebalance the economic interests of the parties in the event of tax or other changes that disadvantage them). This protection may cover the tax treatment of direct disposals and possibly also OITs. Given the critical role that the availability of such protection has in decisions to invest, it is important that they are respected in the event of law changes of the type contemplated by the draft toolkit. It seems appropriate to incorporate this recommendation in the final version, though no mention of it is made in the draft.

Conclusion

The decision whether to tax OITs and, if so, how, is an important policy issue for resource-rich countries. How this is approached will have important implications for the overall attractiveness to investors of the fiscal regime. The Platform's intention of bringing coherence to what has become a very complex and often emotive area of international taxation is laudable. Whether the draft toolkit can achieve this when it becomes final at the end of 2017 is not clear. Many countries already have introduced legislation, which, along with the inclusion of two options in the draft, suggests that an internationally coherent approach may be unattainable.

Both models presented in the draft present the risk of disproportionate taxation of OITs. Model 1 seeks to tax a gain on an OIT of immovable property generating location-specific rents, but does so by deeming a disposal of all assets and liabilities (not just the relevant immovable property) held by the entity in the relevant jurisdiction. In addition, it treats those assets and liabilities as disposed of even if 49.99 percent of the underlying ownership has not changed. It also does not provide any clear means of avoiding double economic taxation if the jurisdiction where the actual seller resides also chooses to tax the transaction. Model 2 provides a more obvious means of providing relief from double taxation by taxing the actual disposal. However, it also introduces the potential for extraterritorial taxation by taxing the entire gain on the relevant shares, even if 49.99 percent of the underlying value derives from assets in other jurisdictions or those that are not immovable property generating location-specific rents.

Deloitte has provided a response to the Platform's request for comments on the draft toolkit. We understand that the response will be published when the toolkit is finalized later this year. We will provide a link to our letter, along with an update on the final version of the toolkit, in a later edition.

Oil and gas rotator programs: Unlocking efficiencies at every turn

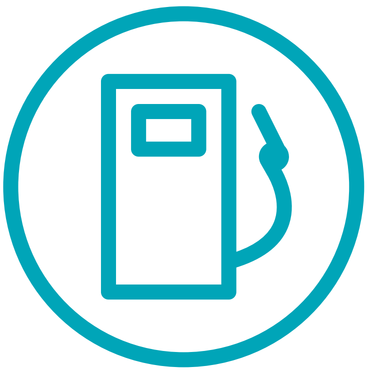
Carlos Carpio and Lisa Dorvinen, Deloitte US

There are two types of rotations—one mechanical, the other human—which drive the action on drilling rigs around the world. The mechanical one involves steel, tungsten, and diamond bits twisting through the earth toward a hoped-for strike. The human one is the continual rotation of oil and gas services personnel, also known as rotators, who keep rigs and fields operating offshore and in remote lands. Dozens of energy jobs are staffed on weeks-on/weeks-off rotation schedules, from platers, pipefitters, and riggers to engineers, architects, and geophysicists.

The more specialized and expensive the rotators' skills, the greater the incentive for energy service providers (service providers) to reduce their downtime. One way to do that is to loan or second them to other drilling sites, which may be a state, country, or continent away.

These deployments do trim idle time, but they also increase rotator program complexity and requirements related to talent management, rewards, compliance and data management—factors that together signal the need for a strategic approach to utilizing this unique population in alignment with a service provider's broader business objectives.

Developing a rotator strategy is like opening a safe's combination lock. Each action, each turn of the dial, sets a tumbler. When all the tumblers are in place, the vault door opens to reveal great value—in this case a strategy-driven, business-aligned and financially efficient rotator program.



Talent management: From model to pipeline

Most rotators live nomadic lives. Those with specialized, highly valued expertise may end up at half a dozen locations in a given year. While rotators are indispensable resources on rigs, demand for their skills fluctuates with the vagaries of the oil and gas business. This fluctuation can lead service providers to hurried hiring in boom times, fast firing at downturns, and a resulting shortage of talent for the next uptick.

Underlying this unfortunate cycle for many services providers is the lack of a rotator talent model—a framework to help align global mobility with business strategy and improve the structure and execution of rotator deployment. A sustainable rotator talent model is the requisite path to establishing a talent pipeline that satisfies the requirements of today's reliably unpredictable markets.

Development of a talent model can begin with a basic supply and demand analysis. Where do we need rotators? From where are we sourcing them? How deep are our rotator benches should a sudden need arise?

Geographic patterns identified through an analysis of rotator deployment may support the creation of regional resource pools adapted to local needs. Segmenting rotators by market, with local talent earning local market rates, can help control costs. Rotators also can be segmented and assessed by the scope of their work in a hierarchy of domestic, regional, and international resources.

Segmenting talent in this way provides the foundation for a talent pipeline. Top domestic performers can move into regional slots, regional stars become international resources, and international superstars become global legends. Career-pathing and competency models can help identify promising candidates and create opportunities for cross-product and cross-market development. With the talent model established, a service provider facing the next market downturn will know its rotator workforce—which people are where, who can be moved, who is untouchable, and which ones are reduction-in-force candidates.

Rewards: From visibility to rationalization

Compensation is integral to rotator talent strategy. Tying the talent pipeline to compensation can help more accurately reveal the costs of doing business in a region.

Making that connection may not be easy. In-demand rotators routinely strike individual agreements with service providers, and their total rewards profiles can be hard to assemble. Greater visibility into rotator compensation can enable analysis that guides pay rationalization by product lines and work locations.

From this analysis, service providers can develop individual compensation strategies for segmented populations. Pay strategies strengthen and support the talent model. Standardized, harmonized pay structures promote greater internal equity. Improved reward structures helps match rotators to assignments and compensation.

Rotator tax regulatory issues

Most people, and most service providers, do not want to pay more taxes than they owe. Nor do they want to incur the fines and penalties that can result from underpayment or late payments. When rotators are involved, it is not unusual to rely on intercompany invoices to calculate the employment taxes payable to each country in which a rotator performs services.

To fulfill its employment tax obligations, a service provider needs to know who is working, where and when they are working, the compensation they receive for their work, and select personal information. That is no small task in the world of rotators, as energy services companies can struggle to track rotators' whereabouts and movements.

As noted, visibility into rotator compensation can be less than ideal, which compounds the problem. Special contract terms may generate lump-sum bonuses for workers in high-demand, specialized roles, with no indication of where they earned the money.

As efforts progress to improve talent management, align compensation, and track employment movement, savings attained by avoiding overpayments and late payment or underpayment penalties could help fund rotator efficiency initiatives, increase international margins, or support more competitive bids on future work.

Data management

Each element of a rotator strategy represents a turn of the dial in unlocking efficiencies and value within a rotator. These elements include identifying geographic rotator deployment patterns, segmenting rotators by market, developing career-pathing and competency models, tying the talent pipeline to compensation, efficiently fulfilling employment tax obligations—program. The common factor underlying each one is data. By effectively capturing, cleansing and managing critical data across the enterprise, service providers can apply data analytics that help produce previously unimaginable insights into the activities and management of their rotator population, including:

- *Utilization* – Are current rotational schedules maximizing the utilization of rotators? Do they deliver the maximum revenue-generating activity?
- *Cost* – Once all costs are factored in, is the use of an international rotator bringing the value and margin expected? Or, is work being done, unknowingly, for practice?
- *Data model* – Does the data structure regarding individual employee groups facilitate analysis of key points of interest and thereby enable more informed decisions?
- *Rotator demographics* – What can segmenting available data reveal about rotators by service line, location and other key decision-shaping factors?
- *Process standardization* – By automating intercompany rebilling and other vital rotator-related processes, can costs be more accurately assigned to the correct entities based on where the rotators actually work rather than where they are assigned?
- *Tax efficiencies* – By better understanding available skills sets, costs, and tax footprints, can more effective choices be made when sending an employee to a specific location?
- *Risk management* – Is the necessary hard data available to support the service provider's tax positions if the local tax authorities conduct an audit?

The data that can help lead to these and other types of insights about a rotator program may already be available within service provider organizations. Often, it is a matter of identifying where the data resides, refining processes for producing the necessary level of granularity, and then having the people, tools, and processes in place to analyze the data and generate the desired insights.

Steps to strategic rotation

Developing a sound strategy for the deployment and management of rotators can help service providers address several related talent considerations (see Rotator strategy: key areas of impact). Elements of the process include:

Segmenting talent rationally. Creating regional talent pools and compensating rotators based on what specific markets will bear can help contain rotator costs while providing appropriate compensation. Segmentation can include designating rotators as domestic, regional and international resources.

Turning on the talent pipeline. Segmentation provides the foundation to develop and nurture promising rotators, turning domestic personnel into regional talent, regional stars into international players, and international achievers into go-anywhere problem solvers.

A talent pipeline can prove invaluable when the time inevitably comes for force reductions. Superstars can be protected, promising talent redeployed efficiently, and identified reduction-in-force candidates addressed appropriately. When the time comes to ramp operations back up, key talent resources are securely in place.

Addressing the tax requirements. With accurate tracking of rotators in place, service providers can begin to proactively pay employment taxes in the right place, in the right amount, at the right time.

Establishing a data management and tracking system. Knowing where rotators are and what they are working on provides a foundation for capturing more value from these vital employees.

Rotator strategy: key areas of impact

Establishing a strategy for the management and deployment of rotators can provide an impressive array of potential benefits:

Speed to deployment. Service providers can send employees where they need to be quickly and compliantly.

Global talent mix. Talent resources can be balanced correctly with revenue opportunities.

Total rewards design. Employee value propositions can be rationalized to help maintain competitiveness, attract and retain talent, and achieve margin targets.

Payroll reporting. Reporting can accurately reflect where employees are and whether reporting is required.

Ease of administration. Rotator locations can be tracked effectively anytime, anywhere.

Geopolitical landscape. Local processes and required processing times can be accurately identified for different employees.

Cost efficiency. Service providers can improve margins by understanding the rotator value/cost equation.

Tax compliance. Service providers can understand the triggers for mobile employee individual tax filings in different locales, whether they are at risk of corporate tax exposure.

Driving value through rotator strategy

Rotators are the backbone of revenue generation for many oil and gas companies. Mobile employees provide the technical skills needed to keep operations running smoothly in far corners of the world, fill local capability gaps, transfer knowledge and enter new markets. By taking a strategic approach to talent management, compensation, tax compliance and data—an approach that aligns with the overarching goals and strategies of the business—service providers can be better equipped for the demands, vagaries and opportunities of the energy business. They also can potentially unlock hidden value in their rotator programs.

Gulf Cooperation Council: Differing approaches to taxation across the Gulf

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In the April 2017 edition of the Global oil and gas tax newsletter, we discussed the introduction of value-added tax (VAT) by the Gulf Cooperation Council (GCC) states (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates), including the rationale for tax reform in the region and the potential consequences of VAT for the oil and gas sector. Since that time, the two largest economies in the region, the Kingdom of Saudi Arabia (KSA) and the United Arab Emirates (UAE) have both confirmed an implementation date of January 1, 2018 and released domestic legislation indicating how VAT will apply to the oil and gas sector. Some differences in policy approaches between these two countries already have emerged. Participants in the sector will need to keep appraised of these approaches and developments across the region as VAT is introduced.

This article examines the framework for VAT across the GCC states, the specific rules applying to the oil and gas sector in both the KSA and UAE, and the approaches that may be taken in the other GCC states. We also discuss major impacts for the oil and gas industry and—given the short timeframe remaining until VAT "goes live"—what actions businesses should be taking to prepare for VAT implementation.

The GCC states already form a customs union and operate as a coordinated system for other indirect taxes, such as customs duty and excise duty. Unlike most countries, hydrocarbons are not subject to excise duties by the GCC states. VAT also will be largely coordinated, with the six states agreeing on the broad principles of taxation, including the following:

- A headline VAT rate of five percent
- "Place of supply" rules that determine taxing rights for imports, exports, and cross-border transactions in goods or services
- Principles for taxpayers to recover VAT charged to them on expenditure as input tax
- A common registration threshold, i.e., VAT registration will be mandatory where turnover exceeds the local currency equivalent of USD 100,000.

These common principles are set out in a Unified VAT Agreement for the GCC states (the Agreement). In addition to formalizing the mandatory aspects of VAT, the Agreement allows countries to take domestic positions in certain specified areas. The combination of mandatory and optional provisions in the Agreement is broadly similar to the EU VAT directive; however, it should be noted that the GCC Agreement is much shorter and contains less detail than its EU counterpart. Nevertheless, it is clear that many VAT principles from Europe and other VAT systems worldwide have been considered in the design of VAT in the Gulf.

The oil and gas sector is a hugely important sector in the region—and indeed makes up a significant part of the economy of each GCC state. Therefore, the Agreement gives individual governments discretion to determine the domestic VAT treatment of the industry. While the standard rate of five percent will apply to all domestic supplies as a default, each country may subject its oil, oil derivatives, and gas sector to tax at zero rate according to the terms and limitations set by each member state. The optional zero rate will allow a supplier to charge VAT at zero percent on a sale, while still benefiting, in principle, from the right to recovery on associated costs.

A straightforward domestic approach in the KSA

The KSA was the first country to release domestic legislation, and it is notable for taking a relatively broad-based approach to the application of VAT. The KSA rules do not provide any exemptions or zero rates for healthcare, education, or food items, despite being permitted by the Agreement to do so for social reasons. Similarly, there are no special rules for VAT in the KSA oil and gas sector. Supplies, therefore, will be charged five percent VAT, as will be the case for other goods and services.

This will have a small inflationary effect on fuel sold to consumers at the pump (even though fuel prices in the KSA already are comparatively low for the region), but should not form part of an overall cost to producers and refiners, given that nearly all businesses in the sector will be able to recover VAT in full.

While there is no domestic exemption, nonetheless, many producers will have a high proportion of zero-rated sales. The export of any goods from the GCC states is zero-rated and the bulk of production in the KSA is destined for global markets.

Added complexity in the UAE

The UAE has elected to provide two forms of domestic relief in the sector, but the full details of these are still to be established. At the time of writing, the UAE had released its domestic VAT law, but not the associated executive regulations that will provide further detail.

Under the UAE approach, the supply of crude oil and natural gas will qualify for zero rating, which will remove the cost of VAT on the main unrefined products of upstream activities. Since unrefined products are exclusively supplied to other businesses in the sector, this zero rate should not have any overall effect on the cost to the supply chain because any VAT charged on these products would be recoverable in full as a credit, absent zero rating. However, it does remove the cash flow impact of VAT on these commodities (which could be significant on high-volume transactions), and may reduce administrative obligations for pure upstream producers. The exact scope of the zero rate is not yet confirmed; for example, it is not known whether liquefied natural gas (LNG), often treated as an equivalent product to natural gas in other jurisdictions, will also qualify for zero rating.

A second relief will apply more broadly across the sector. A reverse charge mechanism will apply to all other sales of hydrocarbons (including refined oil or gas products) to a recipient that intends to resell the products or use them to produce energy. Under the reverse charge, VAT is, in theory, chargeable on all such products at the five percent rate, but the VAT obligations are passed on to the recipient, who can at the same time, offset the VAT payable against its creditable input VAT. In practice, the VAT charge will not result in any cash tax payment by either the supplier or the recipient of the goods. In this way, the net effect of the reverse charge is similar to zero rating in most cases, but with additional compliance obligations.

No VAT relief will apply to final domestic sales for consumption, so any fuel sold at the pump will be subject to a five percent VAT charge.

The VAT rules for the oil and gas sector in the UAE are likely to provide some cash flow relief to upstream and midstream sector participants. It is important to note, however, that the application of the zero rate and the reverse charge rules are limited to sales of hydrocarbons. Other supplies made in the sector, including equipment and ongoing operating costs, will not qualify for relief and will be charged VAT, which may form a cash flow cost for these businesses. VAT still will be an important consideration for all industry players in the UAE, and could result in financial, as well as operational costs.

Other GCC states

At this point, it is difficult to predict whether other GCC states will adopt a broad-based approach to the domestic VAT rules on oil and gas with no domestic relief (as in the KSA), or will apply a zero rate to some parts of the sector. The oil and gas industries are significant parts of the economy in each GCC state and even the cash flow effect of introducing a zero rate for upstream could be significant. We see it as less likely that individual states will elect to relieve domestic prices with a zero rate for sales of oil and gas products to individuals.

Impact of VAT introduction for the oil and gas industry

1. Cash flow

Regardless of whether a domestic zero rate applies in their country of operation, many producers will have a large proportion of zero-rated sales due to export activities. This is likely to result in the creditable VAT incurred on capital and operating expenditures exceeding the VAT charged on revenues. Refunds of this creditable tax should be available in principle, but may take a long time to be paid in practice. Delays of over a year in repaying VAT refunds are not uncommon in other jurisdictions. At the least, businesses should understand the potential cash flow costs. Practical arrangements often can be adjusted to minimize the VAT at stake, and actions can be taken to accelerate repayment by authorities.

2. Territorial scope of offshore activities

In many countries, VAT applies only to offshore activities carried out within territorial waters, which usually extend 12 nautical miles from the shore. The KSA law includes areas outside territorial waters within the scope of the tax. While further detail is needed, this suggests that activities in fields within the "exclusive economic zone" will be subject to VAT. The UAE has not yet given any formal view on the territorial scope of its VAT regime. Businesses, including service companies operating offshore, should be aware of the potential for VAT to apply to their activities and monitor any developments in this respect.

3. Registration for exploration activities

In addition to the mandatory registration threshold, the GCC agreement specifies a default minimum annual turnover for businesses to voluntarily register for VAT (approximately USD 50,000). This rule would have serious consequences for businesses in the exploration or preproduction phase because VAT registration would not be permitted and the recovery of VAT charged on costs would be difficult or, in some cases, not possible at all. Both the KSA and UAE have extended the scope of registration to allow businesses with annual expenditure over that amount to register, which mitigates the effect of this restriction. It is worth noting, however, that nonresident businesses will not qualify for this rule. Nonresidents operating in a GCC state without a local branch or establishment, especially those incurring significant local costs, should carefully consider whether they will be able to register locally to recover VAT on these costs.

4. Contracts

Many existing contracts in the GCC region do not anticipate VAT being charged and may not include a specific VAT clause to determine which party is liable for VAT due. This can lead to an unintended VAT cost, even where VAT is fully recoverable by the recipient of the supply. The default position is that any amount in a contract will be VAT-inclusive, unless otherwise specified. Businesses unable to change their price to reflect the introduction of VAT on January 1, 2018 may face a significant impact on profits. The KSA has announced a grandfathering rule that will allow VAT relief for some existing contracts, but this will apply only in certain circumstances and, at most, for a period of one year from the date VAT is introduced. Potentially affected businesses in the sector should review and update contracts as necessary to protect their positions.

5. Administrative requirements

Whilst VAT in the GCC should be conceptually similar to VAT regimes in other countries, preparing businesses is almost certain to be a significant exercise, and there will be local administrative requirements to be aware of in each country. For example, the requirement in the KSA law for tax invoices to be issued in Arabic is proving challenging for many businesses using international ERP systems. In the UAE, the authorities have signaled that an Emirate-by-Emirate sales reporting requirement will likely be part of the regular VAT submission process, which could inject an extra process for businesses that currently record information only at a federal level.

Getting ready for VAT

Moving a business's processes from an environment without VAT to a state of VAT readiness requires a significant transformation process. There is much for oil and gas businesses to do over the next few months to be ready for the introduction of VAT, particularly those businesses with operations in the KSA or UAE. Following the implementation of VAT in Malaysia in 2015, businesses were asked how much preparation time they considered necessary to be VAT-ready: The average was nine to 12 months, including time to deal with unanticipated delays. Preparation is key to a smooth transition process.

Revision of SYSCOHADA accounting rules: Implication for extractive companies in Africa

Vylie Sayam and Nicolas Balesme, Deloitte Francophone Africa

In January 2017, the OHADA[1] Council of Ministers adopted a new Uniform Act relating to accounting law and financial information (SYSCOHADA).This act aims to integrate with the evolution of international accounting standards to make financial information in the OHADA countries more consistent and relevant.

The new SYSCOHADA rules will enter into force on January 1, 2018 for entities' statutory accounts and on January 1, 2019 for consolidated/combined financial statements. Companies will face challenges as a result of the new rules, specifically on issues relating to the structure of financial statements, transitional arrangements for the revised accounting policies, and the treatment of specific transactions.

Some changes will affect the extractive industries, including changes to the treatment of:

- prospecting costs and mineral resource extraction expenses;
- costs of decommissioning, restoration and reconditioning; and
- provisions and contingent liabilities, pension liabilities, leases, major inspections, and the option to use a component approach in respect of significant assets.

This article reviews the potential impact of these changes on extractive companies operating in the OHADA area.

Pragmatic presentation of financial statements

The components of financial statements are simplified under the new rules:

- The balance sheet is presented on one or two pages instead of four pages.
- The income statement is on one page instead of four pages, with greater simplicity in the analysis of key components of income.
- A real cash flow table is on a single page, with easier identification of cash arising from operational, investing, and financing activities, replacing the former TAFIRE,[2] which was presented on four pages.
- There are 36 notes to the financial statements that cover variations from the prior year and comments on significant deviations. Entities will be authorized to delete notes that are not applicable.

At this stage, there is a lack of guidance from tax authorities in the region on the application of the new presentation of financial statements for tax purposes. In the absence of such clarifications, entities will potentially need to prepare two sets of financial statements in 2018—one for statutory reporting and the other for tax purposes.

[1]OHADA is the acronym for the Organisation pour l'harmonisation en Afrique du droit des affaires (Organization for the Harmonization of Corporate Law in Africa). The current OHADA members are: Benin, Burkina Faso, Cameroon, Central African Republic, Chad, Comoros, Cote d'Ivoire, Democratic Republic of Congo, Equatorial Guinea, Gabon, Guinea, Guinea-Bissau, Mali, Niger, Republic of Congo, Senegal, and Togo.

[2]Tableau financier des ressources et emplois, which may be translated as the Statement of Sources and Application of Funds.

Transitional arrangements

To mitigate the impact on equity from the application of this change in accounting policies, regulatory bodies have introduced transitional arrangements with the creation of two special accounts: 4751 transitory asset and 4572 transitory liability. These accounts will be used to record adjustments to assets and liabilities that arise from conversion to the updated SYSCOHADA. The balances of these two transitional accounts are to be transferred to the income statement over a period that does not exceed five years.

Transitional treatment is prescribed for specific transactions, such as:

- Prospecting costs
- Decommissioning costs
- Provisions
- Pension liabilities
- Component approach for significant assets
- Leases
- Major inspections
- Other costs, such as R&D costs, investment property, service concessions, etc.

Changes to accounting for prospecting costs and mineral resources extraction expenses

Currently, there are no specific accounting rules for the treatment of expenses related to the prospecting and evaluation of mineral resources. Investments at the early stage of extractive projects are accounted for on the basis of tax guidelines, contracts (e.g., production-sharing contracts - PSCs) or group accounting principles (for subsidiaries of multinational companies). These expenses generally are capitalized as an asset until the beginning of production.

The amended SYSCOHADA—inspired by IFRS 6, "exploration for and evaluation of mineral resources" and IFRIC 20, "stripping costs in the production phase of a surface mine"—provides precision on which kind of expenses should be considered as creating a prospecting and evaluation of mineral resources asset, and clarifies the accounting treatment and disclosures for such charges.

Capital expenditures on operations that occurred after conclusion of a contract (i.e., a PSC or concession agreement) and before demonstration of the technical viability of a project, will be able to be expensed or capitalized at management's discretion. Additionally, the reform recommends recording mine stripping costs as stock (if the result of the process is a stock of ore) or as an asset (if it provides better access to ore resources).

To capitalize expenses, the following recognition criteria, similar to those prescribed by IFRS, must be fulfilled:

- the resource must be controlled by the entity as a result of past events; and
- there must be a resource from which future economic benefits are expected to flow to the entity.

With the reform, financial statements will disclose the accounting method applied to prospecting costs and mineral resource extraction expenses. Amounts recorded on the balance sheet and income statement will have to be explained in the notes, as well as operating cash pertaining to these extractive operations.

The key issues for extractive industry can be summarized as follows:

Challenges	During the transition	After the transition
Accounting impact	• Analyze capitalized expenses • Reclassify ineligible assets (capitalized expenses not meeting the new criteria) in a special account (4751) and the option to amortize over five years or less	• Choose to capitalize or expense • Amortize based on the useful life or unit of production • Define of Cash Generating Unit (CGU) and impairment testing
Reporting impact	Identify information to disclose	Implement procedures to collect information to disclose

Decommissioning costs

The treatment of decommissioning costs is not specifically addressed in the SYSCOHADA accounting rules currently. In practice, a provision arising from obligation of restoring site is estimated and recorded by some companies (mainly subsidiaries of multinational groups) on the basis of a contractual agreement (PSC or concession) or group accounting policies. Accounting treatment is not uniform among practitioners. To remedy this situation, SYSCOHADA's regulating bodies have adopted new rules based on international standards. Decommissioning costs are will be accounted for in financial statements as a provision if there is an existing mandatory obligation, the outflow of resources is probable, and an estimation of the amount can be reliably made. The counterpart account of the provision is:

- A tangible asset when the obligation to dismantle occurs at the construction of the asset (immediate degradation): The provision and the asset will be estimated by determining the fair value of decommissioning costs when time value of money is significant.

- An expense in the income statement when the obligation to dismantle arises during the use of the asset (progressive degradation): The assessment of the provision will be made on an ongoing basis; as the degradation takes place, the provision will be estimated by determining the present value of dismantling costs when time value of money is significant.

The main points are summarized below:

Challenges	During the transition	After the transition
Accounting impact	• Determine when the obligation to dismantle occurs • Evaluate decommissioning costs • Estimate fair value parameters • Account the provision and the asset or the expenses	• Choose to capitalize or expense • Amortize based on the useful life or units of production • Determine deemed financial income that arises from time value of money effect on the provision
Reporting impact	Identify information to disclose on estimation of decommissioning costs and present value	Implement procedures to collect information to disclose

Other areas affecting extractive companies

Provisions and contingent liabilities

The amended SYSCOHADA will introduce a new definition and recognition criteria for provisions and contingent liabilities that derive from IAS 37 provisions, contingent liabilities and contingent assets. A provision will have to be recognized when:

- an entity has a present obligation (legal or constructive) as a result of a past event;

- it is probable (i.e., more likely than not) that an outflow of resources embodying economic benefits will be required to settle the obligation; and

- a reliable estimate can be made of the amount of the obligation.

During the transition period, an analysis of provisions recorded in accounts will have to be performed to identify those that cease to qualify under the amended definition.

Pension liabilities and retirement benefits

Accounting for provisions relating to pension liabilities and other retirement benefits will be compulsory, rather than optional. Estimation of the provision on an actuarial basis will be required only for public offering entities.

During the transition to the amended accounting rules, an entity that records pension liabilities for the first time will be able to:

- record a provision for prior commitments directly as a charge to retained earnings; or

- charge the total provision in the 2018 income statement; or

- reclassify the amount of the provision for prior commitments in the special account 4752, with a choice to transfer the expense to the income statement over a period from one to five years.

Leases
The revised SYSCOHADA prescribes rules for identification of lease arrangements and their treatment in accounts of lessees and lessors. This new accounting policy is consistent with IFRS 16. In the interests of simplicity, the regulating bodies have determined that the application of the lease rules will apply only to contracts signed after January 1, 2018.

Major inspections
When an entity intends to carry out a major inspection on an asset at regular intervals, a provision for major repairs can be recognized in accordance with current OHADA accounting norms.

The revised SYSCOHADA does not permit accounting for such provision, which instead will have to be charged in the special 4752 account. Extractive companies should consider the component approach in accounting for their significant assets because provisions for major inspections will not be permitted under the revised SYSCOHADA rules.

Based on IAS 16 Property, plant and equipment, the new SYSCOHADA recommends the recognition, in the carrying amount of the asset, of a component major inspection that is amortized until the next major inspection. This implies a requirement to analyze, by component, significant assets that require such major inspections.

Use of the component approach for significant assets
An entity can elect to use the component approach for assets that are significant in terms of value and comprised of items with different useful lives (e.g., industrial material and equipment for mining or oil and gas activities).

During the transition period, for an asset acquired before the SYSCOHADA reform, an entity will be able to choose between maintaining an unchanged asset value or allocating the net book value to the identified components. In either case, the chosen method will not have an impact on equity.

Implications
Entities in the extractive industries have operations that require capital-intensive expenditures before there is confirmation that resources and future operating cash flows exist. In the absence of precise SYSCOHADA accounting rules for the treatment of these expenses, the tendency has been to capitalize these charges as intangible assets and to avoid a violation of OHADA policy, which states that when the net equity becomes less than half of the share capital, the company must recapitalize under the OHADA Uniform Act.

Despite the transitional arrangements, the new SYSCOHADA implies a gradual reclassification of a significant part of these expenses to the profit and loss account and will lead to a greater focus on the requirement to maintain the level of net equity.

Moreover, when the tax authorities in each member country endorse the new SYSCOHADA, tax treatment not covered by contracts (e.g., PSCs) or conventions may become problematic. Some countries have elected ad hoc technical committees to work through the tax consequences of the OHADA accounting reform.

Indonesia: Update on the cost recovery regime and introduction of the gross split regime in the upstream industry

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The Indonesian government recently issued a new regulation dealing with cost recovery and income tax for the upstream oil and gas industry. The government's intention to amend the upstream fiscal regime to encourage exploration, stimulate the investment climate and provide enhanced legal certainty for the sector was mentioned in the September 2016 edition of this newsletter.

The main changes made by the regulation are as follows:

- New incentives (in addition to the existing investment credit) are provided to upstream businesses, including accelerated depreciation and a holiday from the domestic market obligation (DMO, i.e. the obligation to sell production in the domestic market, where prices typically are below international market prices). Additional incentives will be set out in forthcoming regulations.
- A new profit-sharing scheme, known as dynamic profit sharing, is introduced. Previously, production sharing was based on a fixed percentage of production volume without considering the prices, production levels, profitability, etc. The new system is intended to distribute the risks and benefits from changes that affect upstream activities, including changes in prices, production levels, and the ratio of revenue and costs. However, it is unclear whether dynamic profit sharing can be applied to existing production sharing contracts (PSCs), which share according to a fixed ratio.
- The following are now cost recoverable:
  - Environmental and community development costs incurred during the exploitation phase
  - Employees' income tax borne by the contractor paid as a tax allowance (using the gross-up method)
  - Interest recovery incentive (which provides additional cost recovery for certain investments)
- The residual book value of tangible assets that no longer be can used due to natural factors or force majeure can be treated as operating costs (which are subject to immediate cost recovery and tax deduction)
- Income tax on first tranche petroleum (FTP, an amount of production that is shared before cost recovery and the profit oil/gas split) will be calculated when the accumulated FTP received by a contractor exceeds the remaining amount of unrecovered operating costs
- The following tax reliefs are applicable for contractors in both the exploration and exploitation phases. Reliefs in the exploitation stage shall be granted by the Minister of Finance (MOF) based on consideration of project economics:
  - Exemption from the collection of import duty and income tax on the import of goods used in petroleum operations (as defined by law)
  - Exemption from VAT and luxury goods sales tax for:
    - Acquisition of certain goods and services
    - Import of certain goods
    - Utilization of certain foreign intangibles
    - Utilization of certain imported services used in petroleum operations
- Reduction in land and building tax (LBT) of 100 percent of the tax payable as set forth in the notification of tax due during the exploration stage, and a 100 percent reduction of LBT charges relating to offshore blocks during the exploitation stage of a PSC
- Certain payments for the use of assets shared by multiple PSCs will be exempt from withholding tax and not subject to VAT if they satisfy certain conditions—a tax treatment that also may apply to overhead allocations made by the parent company

- Income received in respect of uplift[3] and the transfer of a participating interest in a PSC will be subject to tax at a rate of 20 percent and 5 percent/7 percent[4] of the gross amount, respectively
  - The taxable income after deduction of final income tax will not be subject to further tax (this exemption principally applies to branch profits tax)
  - The regulation also mandates that the contractor must report the value of such transactions to the directorate general of taxes and the directorate general of oil and gas

With the agreement of the relevant authorities, an existing PSC may incorporate the provisions of the regulation, but only if this is agreed upon within six months from the date the regulation became effective.

Gross split PSC regime

In January 2017, the government also introduced the gross split PSC regime to incentivize petroleum activities. Under this regime, total gross production is split between the government and the contractor and, consequently, there is no allocation of production for FTP, cost recovery, or profit sharing as in the previous PSC regime.

There are three steps for calculating the gross split of production between the government and the contractor, with the gross split attributable to the contractor comprising (1) a base split, (2) variable components, and (3) progressive components, as follows:

Gross split = base split + variable components + progressive components

Base split is the allocation set out in the PSC at the time the field development plan is approved. The base split may be adjusted by the variable components and progressive components. For crude oil, the base split is 57 percent for the government and 43 percent for the contractor. For natural gas, the base split is 52 percent for the government and 48 percent for the contractor.

In the gross split PSC, the base split may be adjusted to take commercial factors into account. The intention is that the contractor will get a higher production split for higher risk or higher cost developments. If the economics of a field or a group of fields do not reach a certain threshold, the Ministry of Energy and Mineral Resources (MoEMR) may grant an additional percentage of production to the contractor. On the other hand, if the economics exceed a certain threshold, the MoEMR may require allocation of an additional percentage to the state. The additional percentage may be given on the approval of the first and subsequent plan of development (PoD).

In addition, the split is adjusted to take into account specific field-related conditions. The contractor will propose variable components to be applied to the base split in the PoD for the field, such as the PoD status, field location, reservoir characteristics, available infrastructure and carbon dioxide and hydrogen sulphide content. When the development of a field is approved, the production sharing is stipulated pursuant to the base split adjusted by reference to the agreed upon variable components. Progressive components also will be taken into account, including the expected price of the crude oil and/or natural gas, and the cumulative total of the oil and natural gas production.

The government is currently drafting a tax regulation to address the income tax treatment to be applied under the gross split regime.

[3] Compensation received by a party to a PSC in connection with provision of bridging finance to another party in the same PSC.

[4] 5 percent if the block is in the exploration phase and 7 percent if the block is in the exploitation phase.

South Africa: Withholding tax rules

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Although South Africa levies relatively few withholding taxes, there are a number of important features in the rules applicable to the oil and gas industry. This is relevant in regards to the increased level of business activity that is anticipated in the industry in South Africa should the government move forward on key issues, such as amendments to the Mineral and Petroleum Resources Development Act, a framework for preliminary shale gas exploration in the Karoo region, and the gas-to-power policy.

The Tenth Schedule to the Income Tax Act in South Africa was introduced in 2006 to provide an incentive for companies to invest in the high-risk arena of oil and gas exploration and to create transparency and certainty for oil and gas companies by providing a clear tax framework—both for the South African Revenue Service (SARS) and oil and gas companies. Before 2006, the regulatory regime for oil and gas exploration and production was contained in prospecting lease OP26. The Tenth Schedule effectively codified certain tax aspects of the OP26 regime and introduced some new tax principles for oil and gas companies.

This article looks at some of the withholding tax rules applicable to oil and gas companies, as contained in the Tenth Schedule and elsewhere in South Africa's Income Tax Act.

Dividends tax

The dividends tax is normally levied at a rate of 20 percent on the amount of any dividend paid by a company that is a resident of South Africa or listed on the South African stock exchange. A nonresident (e.g., a company operating by way of a branch in South Africa) is not subject to the dividends tax and no branch remittance tax currently applies in the country. The dividends tax rate may be reduced under an applicable tax treaty.

The Tenth Schedule provides that the dividends tax rate applicable to any dividend paid by an oil and gas company out of oil and gas income is zero percent. Two key requirements must be met to qualify for the zero rate:

01. The company paying the dividends must be an oil and gas company; and
02. The dividends must be derived from oil and gas income.

An oil and gas company is defined as a company that:

- Holds an oil and gas right as contemplated in the Mineral and Petroleum Resources Development Act (including a reconnaissance permit, technical co-operation permit, exploration or production right, or any interest, such as a participating interest, in such right); or
- Engages in exploration[5] or post-exploration[6] in terms of such right.

Oil and gas income is defined as the receipt and accruals derived by an oil and gas company from:

- exploration in terms of any oil and gas right;
- post-exploration in terms of any oil and gas right; or
- the leasing or disposal of any oil and gas right.

[5] Exploration is defined as the acquisition, processing, and analysis of geological and geophysical data or the undertaking of activities in verifying the presence or absence of hydrocarbons (up to and including the appraisal phase) conducted for purposes of determining whether a reservoir is economically feasible to develop.

[6] Post-exploration is defined as meaning any activity carried out after completion of the appraisal phase, including the separation of oil and gas condensates, the drying of gas, and the removal of non-hydrocarbon constituents, to the extent that these processes are preliminary to refining.

To benefit from the zero rate of dividends tax, the company paying the dividend must hold one of the above rights (or an interest therein) or must be engaged in exploration/post-exploration at the time the dividends are declared. The company must also be able to show that the profits from which the dividends are declared were generated out of oil and gas income, as defined.

Withholding tax on interest

Subject to certain exemptions and any rate reduction under an applicable tax treaty, withholding tax on interest is levied at 15 percent on the amount paid by a person to, or for the benefit of, a nonresident to the extent the amount of interest is regarded as having been received or accrued from a source within South Africa. Withholding tax on interest is a final tax.

The Tenth Schedule provides that the withholding tax rate on interest is zero percent on the amount of interest paid by an oil and gas company on certain loans. To qualify, the loans must have funded expenditure of a capital nature that is incurred in respect of exploration or post-exploration in terms of an oil and gas right. There is no definition as to what constitutes expenditure of a capital nature for purposes of withholding tax relief (and the Tenth Schedule more generally), so companies should consider this issue carefully.

To the extent that interest is paid in respect of loans that do not fund the above expenditure, withholding tax on interest may apply.

Withholding tax on services

A new withholding tax covering all service fees was initially scheduled to take effect in South Africa starting January 1, 2016, but the implementation date was postponed to January 1, 2017. It was recently announced that the proposed law will not be introduced at all. Instead, SARS will be entitled to receive information on service transactions that are potentially subject to tax in South Africa by way of the reportable arrangement regime, which imposes an obligation on parties to report certain transactions to SARS within 45 business days of entering into a reportable arrangement or becoming a participant in such an arrangement.

The definition of a reportable arrangement includes the rendering to a person that is a resident (or that is not a resident but has a permanent establishment in South Africa to which that arrangement relates) of consultancy, construction, engineering, installation, logistical, managerial, supervisory, technical or training services. This applies when the service is rendered by a person that is not a resident (or an employee, agent, or representative of that person) who is physically present in South Africa in connection with the rendering of services, the expenditure in respect of the services exceeds (or is anticipated to exceed) ZAR 10 million (approximately USD 750,000), and does not constitute remuneration arising from employment.

Failure to comply with reporting obligations carries the risk of significant penalties. Presumably, the information reported to SARS will be used to determine whether the service provider has complied with any tax obligations it may have in South Africa.

Withholding tax on royalties

Subject to certain exemptions or a rate reduction under an applicable tax treaty, withholding tax on royalties[7] is levied at a rate of 15 percent on the amount paid by a person to, or for the benefit of, a nonresident to the extent the amount is regarded as having been received or accrued from a source within South Africa. Withholding tax on royalties is a final tax.

There is no specific relief from this withholding tax that is applicable to oil and gas companies.

Transactions involving immovable property

Under South Africa's Income Tax Act, where a person acquires immovable property from a nonresident, the person making the acquisition (purchaser) is required to withhold a specified amount from the purchase consideration payable to the nonresident seller as an advance in respect of the seller's potential liability for tax in South Africa. The withholding tax is calculated as a percentage of the purchase consideration and comprises 7.5 percent when the seller is an individual, 10 percent when the seller is a company, and 15 percent when the seller is a trust.

[7] A royalty is defined as any amount received or accrued in respect of the use or right of use of, or permission to use, intellectual property (as defined); or the imparting of, or the undertaking to impart, scientific, technical, industrial, or commercial knowledge or information, or the rendering of or the undertaking to render assistance or service in connection with the application or utilization of such knowledge or information.

There is some uncertainty as to whether these withholding tax rules apply to transactions involving the transfer of oil and gas rights (i.e., whether such rights constitute immovable property for the purposes of the rules). The view of SARS is that the rules do apply, both in respect of a farm-out of a participating interest in an oil and gas right and a transaction involving the sale of shares in a company holding an oil and gas right in certain circumstances.

The withholding tax rules provide that a seller may apply to SARS for a directive that no withholding tax should be imposed, or that a reduced rate of withholding tax should be applied. This may be the case, for example, where rollover tax relief is applicable to the transaction under special rules in the Tenth Schedule or where a tax treaty provides relief.

Conclusion

While many companies are still in the early stages of activity in South Africa and the production of hydrocarbons (and, hence, the payment of income tax and petroleum royalty) lies at some point in the future, withholding taxes are an immediate concern and companies should carefully consider their potential obligations with respect to these rules.

Switzerland: Corporate tax reform – What's in it for commodity traders?

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After the Swiss electorate rejected the Corporate Tax Reform III in a referendum held on February 12, 2017, the Federal Council issued new draft tax reform legislation on September 6, 2017, which is referred to as the Swiss Tax Reform Proposal 17, or STR 17. The revised tax reform could become effective as early as January 1, 2020, but no later than January 1, 2021.

While changes to the draft are possible as it undergoes the legislative process, the final legislation is likely to be similar to the current proposal.

The proposal is seen as a well-balanced and internationally competitive solution that would ensure that Switzerland stays an attractive location for commodity traders in particular.

Fiscal attractiveness has always been a key element supporting the success of Switzerland as an international commodity trading center

Over the last two decades, Switzerland has become one of the main global centers for the commodity trading industry; for example, the country is the number one location for the trading of grain, cotton, and crude oil.[8] Commodity traders chose Switzerland for many reasons, including its political stability, financial infrastructure, and available talent pool, along with its business-friendly tax environment and low tax rates.

Most commodity traders in Switzerland operate under a mixed company regime. Under this regime, which is available for companies whose business is mainly foreign related, only a portion of foreign-source income—typically in the range of 5 to 20 percent—is ordinarily taxed at the cantonal/communal level, while the company is ordinarily fully taxed at the federal level. The effective combined federal/cantonal/communal tax rate (ETR) of a mixed company generally ranges between 9 and 12 percent,[9] depending on the extent of activities, profits, and location of the company.

International pressure on favorable Swiss tax regimes

When the OECD/G20 launched the BEPS initiative in 2013, the OECD labelled the Swiss tax regimes that provide different treatment of domestic and foreign income (e.g., the mixed, holding, and principal company regimes, and the branch finance regime) as ring fenced regimes.[10] In parallel, Switzerland and the EU signed an agreement on July 1, 2014 confirming Switzerland's intent to abolish these regimes.

To remain competitive internationally and retain existing companies and attract new ones, Switzerland has decided to introduce replacement measures for the regimes that are being abolished. The measures proposed in STR 17 include the introduction of a patent box and research and development (R&D) super deductions. There will be a transition period of five years for regimes that are being withdrawn, including a step-up/release of hidden reserves mechanism (see details below), and a general reduction of cantonal tax rates, benefitting all companies regardless of the nature of their business.

New tax measures benefiting commodity traders

Commodity traders currently operating under a mixed company regime will benefit from the following new measures:

[8] The Baseline Report: Commodities published by the Federal Department of Foreign Affairs on 27 March 2013.

[9] The corporate income tax rate varies between cantons and communes, and Swiss tax law permits the deduction of taxes from the taxable base. For this reason, there are many different applicable tax rates and the figures indicated are only illustrative.

[10] Meaning a regime not available to a company trading in the domestic market.

Transition period of five years through tax-privileged release of hidden reserves

Companies benefiting from a mixed company ruling could proceed with a measure that should be similar in its effect to a step-up in the basis of their assets for purposes of calculating future tax depreciation. The difference between the fair market value and prior basis is termed "hidden reserves." STR 17 provides a tax-privileged release of hidden reserves for cantonal/communal tax purposes for companies transitioning out of tax-privileged cantonal tax regimes, such as the mixed company tax regime, and into the ordinary taxation regime. For this purpose, they would have to be valued at their fair market value and the release of their hidden reserves arising from goodwill (not included in the tax balance sheet but agreed to by a formal decision of the concerned cantonal tax administration) would be taxed at a lower corporate income tax rate.

This lower tax rate would apply to profits generated by the company during the five years following the change in the law, which should enable a reduction of the future higher ETR during the first five years following the tax reform. This measure also is designed to provide both a cash and financial statement tax benefit for companies reporting under IFRS or US GAAP.

The tax administration will need to determine the value of companies affected on an individual company (i.e., unconsolidated) basis.

The benefit of this measure for commodity traders should be carefully analyzed because the recognition of the existence of a goodwill could have adverse tax consequences at the time of exit of all or part of the activities to a foreign country, and this will give rise to a disposal of the relevant asset for tax purposes.

Reduction of corporate tax rates

Within the framework of the STR 17 and the abolition of favorable tax regimes, many cantons have announced their intention to reduce their headline corporate income tax rates that currently give rise to ETRs in the range of approximately 12–24 percent (combined federal/cantonal/communal rate). This reduction will be at the discretion of the individual cantons, but most cantons are expected to be in the 12–14 percent ETR bracket. The canton of Vaud has already voted on the future applicable cantonal income tax rate, which will result in an ETR of 13.8 percent. The canton of Zug is expected to reduce its ETR to approximately 12 percent, Schaffhausen to 12.5 percent, Geneva to 13.5 percent, and Fribourg to 13.72 percent. Other cantons, such as Appenzell IR and Appenzell AR, Lucerne, Nidwalden, Obwalden, and Schwyz, already have low ETRs for companies, ranging between 12 and 14 percent.

STR 17 also would provide an option for Swiss cantons to reduce the cantonal/communal annual capital tax on equity for holding participations, intellectual property, and intercompany loans.

Step-up on migration of companies or activities to Switzerland

The STR 17 contains a provision that would apply to companies migrating from a foreign country to Switzerland, or migrating activities and functions from a foreign country into Switzerland. A step-up of asset basis (including for self-created goodwill, which will have to be included in the tax balance sheet) would be available for direct federal and cantonal/communal tax purposes that could be amortized later based on the life of the underlying assets. Goodwill would have to be amortized over 10 years. The same fair market valuation would be applied upon exit from Switzerland and the corresponding capital gains would be subject to corporate income tax.

Time frame

STR 17 is undergoing a consultation procedure until December 6, 2017, whereby various stakeholders can comment on the proposed legislation. A final version is expected to be introduced and voted on in the 2018 spring session of parliament. Since the STR 17 is considered a well-balanced solution drafted with the involvement of all stakeholders, it seems unlikely that there will be a referendum on the legislation. STR 17, therefore, could enter into force as soon as January 1, 2020, but no later than January 1, 2021, as the cantons will need sufficient time to introduce this federal framework law into their cantonal legislation.

Switzerland will remain competitive for commodity traders from a tax perspective

With an ETR of between 12 and 14 percent and other appropriate tax measures introduced by STR 17, Switzerland is expected to remain an attractive location for commodity traders. At the same time, it will provide an internationally aligned tax system that is in conformity with the new international standards, such as OECD's BEPS initiative.

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