7.3 Fiscal Instruments

A wide range of fiscal instruments exists and can be found in practice in a 'fiscal regime' for a mining or a hydrocarbons project. Some are common to all sectors in the economy, such as profits taxes, employment taxes, income taxes, value added taxes (VAT), customs duties, and dividend withholding taxes. Others are specific to the EI sector itself, such as mining royalties and oil production sharing, bonus payments, cost recovery provisions, state participation, fiscal pricing, and service agreements. For the investor the overall tax structure and burden will be more important than the particular tax instruments a government chooses. For the individual government the various instruments have to be selected and combined in ways that fit the particular context or combination of circumstances. If, for example, there is low capacity or a record of poor governance, this suggests a combination of easy-to-administer instruments and limited discretionary power. As a result, no two countries tax the extractive industries in the same way, which leaves plenty of scope for an advisor or researcher to differ on which is 'best' among this "diverse and potentially confusing array of distinct fiscal regimes"[1].

Fiscal instruments can be evaluated against fiscal objectives, taking into consideration differences among the EI sectors, specific state circumstances, and institutional capacity. However, most fiscal regimes use a number of fiscal instruments in combination. The fiscal instruments in such regimes interact and collectively make up a fiscal *package.* This means that a piecemeal evaluation of individual instruments has limited value compared with an evaluation of the fiscal package as a whole. For example, royalties may be a regressive instrument but may well have an important place as part of an overall fiscal system. So, what will be ultimately decisive in assessing the likely performance of a particular fiscal regime is *the combination of all the instruments and provisions it contains*.

With the above important caveat in mind, this section reviews the individual fiscal instruments that are typically used. It also addresses possible incentives such as tax holidays and accelerated depreciation provisions. **Section 7.4** addresses a number of related special fiscal topics and provisions.

[1] IMF (2013) Introduction to J Smith paper, p. 3.

7.3.1 Profit-based Taxes

Profits are revenues minus costs. However, before a profits-based tax can be made workable, there are considerable challenges to be overcome. First of all, there are challenges in identifying what the category of revenues includes, since it will be necessary to value production and also revenues such as ancillary income, financial income, gains on the disposal of contract interests and so on. Production is an incomplete measure of profitability because it ignores the influence of prices and costs. Price is also an incomplete measure of profitability because it ignores production and cost, and both indicators ignore the influence of time on profitability. Field or mine location at best may be a very crude indicator of cost and so profitability, but it is more likely to be very inaccurate and, furthermore, misses out on the influence of price and production (see **Table 7.1** below).

Table 7.1: Fiscal Mechanisms[2]

	Government 'take' responsive to:				
Government 'take' linked to:	**Reserves/ production**	**Oil price change**	**Costs**	**Timing of cash flows**	**Cost of capital**
Production (daily or cumulative)	**Yes**	No	No	Partly	No
Price (price caps or base prices)	No	**Yes**	No	Partly	No
Revenue (price and production)	**Yes**	**Yes**	No	Partly	No
Cost Recovery (uplifts and write-off rates)	No	No	**Yes**	Partly	Partly
Simple Indicators (location, vintage, etc.)	Partly	Partly	Partly	No	No
Rate of Return	Yes	Yes	Yes	Yes	Yes

[2] Source: McPherson, C. (2009). *Fiscal and Financial Policies for Extractive Industries in Turbulent Times,* Resource Curse to Development Conference, September 8-11, Oslo, Norway. Available at: http://www.cmi.no/file/?853 (last accessed 9 July 2012).

There are further challenges arising from the difficulties in establishing costs. For example, applying different depreciation rates and classifying costs for that purpose; applying cost recovery limits; transfer pricing of costs; applying 'uplift' and classifying costs for that purpose, and allocation of cost and ring-fencing issues (discussed below in this Chapter). All of this gives rise to degrees of administrative complexity.

Profits taxes, such as corporate income tax, are appealing on neutrality grounds. A project which is profitable pre-tax will tend to be profitable post-tax since, as long as the rate applied is less than 100 percent, some profit is always left post-tax.[3] In comparison with other fiscal instruments, profits taxes also contribute to international competitiveness, since the application of a profits tax is, in critical investor home states such as the USA and the UK, a prerequisite to obtaining a foreign tax credit (for example, a home country credit for taxes paid to the host country).

Profits taxes are sometimes faulted, however, for the following reasons: deferring fiscal revenues to allow for investor cost recovery; for being less predictable in outcomes than alternatives such as royalties, for increasing the volatility of government revenues (increasing government risk);[4] greater administrative burden related to the need for careful audits of investor costs; and incentives for companies to minimize reported profits.

7.3.2 Production Sharing

Some of the characteristics of a profits tax are evident in production sharing. This is very commonly applied to oil and gas operations in the developing world, although only very rarely to mining operations.[5] In their simplest form, these regimes are roughly equivalent to those based on profits taxes, allowing the investor to recover costs through an allocation of the physical product as 'cost oil/gas (or cost petroleum),' and sharing the remaining 'profit oil/gas (or profit petroleum)' with the government.

[3] Tordo, S., et al. (2010). *Petroleum Exploration and Production Rights: Allocation Strategies and Design Issues*, Working Paper No. 179. Washington, D.C.: World Bank Publications; see also RWI. *Oil, Gas, and Mining Fiscal Terms.* New York: RWI. Available at: http://www.revenuewatch.org/training/resource_center/backgrounders/oil-gas-and-mining-fiscal-terms (last accessed 1 April 2012).

[4] For example, any X percent increase or in prices will increase or decrease profits tax revenues by more than X percent.

[5] The difficulty of marketing minerals relative to crude oil, which has a readily accessed international market, is one reason for the absence of production sharing in the mining sector.

There are four main variants of production sharing which are usually found, each of which is aimed at increasing the government's profit share on the more profitable projects. These are[6]:

1. Daily rate of Production: in which the government share of profit petroleum increases with the daily rate of production from the field or license, often using several tiers. Sometimes this is blended with a scale of prices. Its main weakness is that it is not progressive with respect to oil prices and costs.
2. Cumulative Production from a Project: in which the government share of profit petroleum increases as total cumulative production increases. Not commonly used.
3. R-Factor: in which the government profit petroleum share increases with the ratio of contractor's cumulative revenues to contractor's cumulative costs[7] ('the R Factor'). This is a more advanced version of No.1 above more and more used but does not recognize the time value of money.
4. Rate of Return (ROR): in which the government's profit petroleum share is set by reference to the cumulative contractor rate of return achieved until the period of sharing.

As a result of the similarity to profit taxes, production sharing regimes share the same pluses and minuses when measured against fiscal objectives. At the same time, some elements of production sharing regimes, such as cost petroleum limitation, function more like royalties. Therefore, the similarities with profit taxes should not be exaggerated.

Most states require payment of corporate profit taxes in addition to production sharing in order to allow investors to qualify for a foreign tax credit in its home country.[8]. The combination of the two instruments is illustrated schematically in **Figure 7.4**. This overlay of two fiscal instruments can create administrative difficulties which are discussed below in **Section 7.5**. Some production sharing schemes also require payment of a royalty or allocation to the NRC of a share of total production reserved as a payment of royalty. This ensures a minimum income to the host country even if the allowable cost recovery in the PSC is high.

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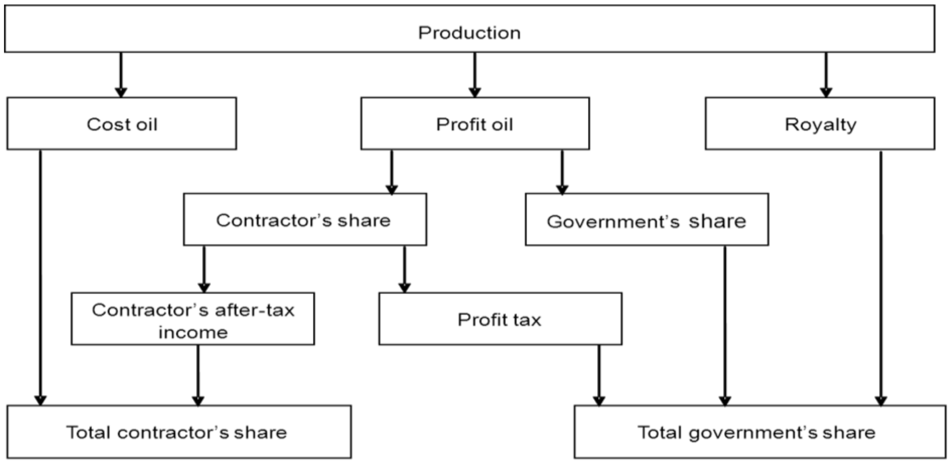
[6] IMF (2012), p.17 (Box 1)

[7] Or the cumulative capital expenditures when the R-factor is defined as a multiple of the investment.

[8] For a discussion of related issues see Mullins, P. (2010). International tax issues of the natural resources sector, in Daniel, P. Keen, M McPherson, C (2010). The Taxation of Petroleum and Minerals: Principles, Problems and Practice, Routledge, London: pp. 378-402.

Figure 7.4: Production Sharing[9]



7.3.3 Corporate Income Tax

The application of Corporate Income Tax (CIT) in the extractive sector is common practice, and is a core element in a fiscal regime for the sector. However, this is a tax on equity and only 'accidentally' a tax on extractive rents. It is attributable not specifically to the oil, gas and mining activities, but to doing business in the country itself. It ensures that the normal return to equity is taxed at the corporate level in the way that it is in other, non-extractive sectors. Some countries take the base CIT rate and increase it, applying this higher rate to the extractives sector: Indonesia does this for mining, while Nigeria and Trinidad and Tobago take this approach to CIT in their petroleum sectors. In many other countries, the practice is to design a separate income tax regime for dealing with the issues specific to the oil, gas and mining sectors which often considers a higher income rate than the base CIT rate as currently in the UK. It is better when such regime remains consistent to the extent possible with the general tax code rules except for those rules specific to the EI sector.[10]

For the government, the appropriate CIT rate for the extractives sector is determined by various, wider objectives. These include: whether the government intends to reduce the general rate over time; whether it seeks to obtain a higher CIT rate for this sector than for others; and how it links to other taxes, such as any additional rent taxation (especially if the rent tax rate adjusts to changes in the rate of CIT in either direction). For the corporate investor, CIT will be assessed in relation

[9] Source: IMF (2011). Production Sharing Agreements. Twenty-Fourth Meeting of the IMF Committee on Balance of Payments Statistics. Available at: http://www.imf.org/external/pubs/ft/bop/2011/11-17.pdf (last accessed 9 July 2012). The focus of the above diagram is on the regime in place for PSCs in Russia.

[10] One common approach is to insert a specific part in the general tax code dealing with the EI sector or alternatively to enact a petroleum and mining taxation legislation referring to the general tax code.

to the aggregate tax impact, and especially the effect of tax on their internal rate of return, or net present value at a threshold discount rate.

CIT can nonetheless distort financing decisions. It is a blunt instrument for the taxation of extractive rents. Its effect is to tax the *full return* to investors, including the required return to holders of equity. If the CIT rate is high, it will discourage investment since the required pre-tax return will be increased, which can be avoided by a tax directed specifically at rents. CIT also has a bias towards debt-financing: usually, it permits interest to be deductible, but not the cost of equity capital.

Valuation for CIT purposes can also present problems. Across the spectrum of extractive resources, there are significant differences in identifying a reference price. For bulk minerals such as bauxite, rutile and iron ore, and indeed for natural gas, valuation is hampered by the lack of transparent and readily available reference prices. This contrasts with the situation a government faces with the price of oil, gold and copper, for example. Minerals are sometimes sold on a contract basis and arm's length pricing may not apply. The risk that this creates for governments may be mitigated by the use of proprietary sources of pricing data, but even then some adaptation will be required for quality and transport cost differentials.

CIT will be usually applied to the resources sector accompanied by particular provisions relating to the tax base. This will typically include a ring-fencing of operations at project level or for the concerned EI sector (see **Section 7.4.3** below).

7.3.4 Royalties

Royalties are specific to resource extraction, and represent the means by which the resource owner (the state) is compensated for the permanent loss of valuable resources. This is the classic rationale for the use of royalties, and the reason why they are not strictly speaking a tax. However, the rationale is more likely to be based on the political reassurance that derives from a regular payment and the predictability it adds to government revenue flows. In the literature on royalties, the application of the royalty instrument is surrounded by controversy for both hydrocarbons and mining projects[11].

The main type of royalty is *ad valorem* royalties; in exceptional cases unit of production (for example, per ton) royalties may apply. Royalties for many metal minerals are generally calculated on an *ad valorem* basis (that is, related to the price of the product) as a net smelter return royalty. The net smelter return is based on

[11] Some such as Conrad see royalties as being valuable in sending a price signal; others have concerns about the links between royalties and depletion rates: see the discussion by R Boadway and M Keen in Perspectives on Resource Tax Design, in (2010) The Taxation of Petroleum and Minerals: Principles, Problems and Practice, pp.27-

the refined metal price less smelting and refining costs. Payments are received earlier in the life of a project than with other fiscal tools. They are also easy to monitor and administer. Different approaches to royalty design exist: it may be based on the value of ore at the mine head or on the net smelter return or on the value of exports after netback for transport and other costs. Royalties for coal or bulk minerals, such as iron ore, are often charged on the basis of the mine head sales price. These are relatively straightforward to calculate. *Ad valorem* royalty rates are often in the range of three to five percent for metals, and five to ten percent for diamonds.[12]

Royalties may also be calculated as a fixed royalty per unit of production, which is simpler to assess. This volume-based approach is unlikely to be the most appropriate method for many kinds of minerals.

Royalties have the advantage for a government that they are relatively predictable and can help to ensure that companies make some payments to government even in times of low mineral prices and low revenues. The appeal of royalties on gross revenues lies in the early dependable revenue they produce and in their apparent simplicity of administration. From the start of the producing life of a project revenue will continue to the end of the life of the field or mine.

For the company they have the disadvantage that they are calculated on production, not profits; a high level of production does not necessarily equate to a high level of profit. A project with high costs could pay as much as one with low cost, if the production is the same. The company may have an incentive to prematurely end an ongoing project and not take on one that has production that is marginal.

The biggest drawback of these two kinds of royalty is in their lack of sensitivity to profit, which makes them regressive rather than progressive, and distortionary rather than neutral in a fiscal sense. Where *ad valorem* or per unit royalties feature prominently in a fiscal regime, their insensitivity to profit may unduly limit the range of investment projects undertaken and/or cause premature abandonment of production as costs rise and margins fall.

Another drawback is that they are not as easy to administer as is sometimes thought. For example, the valuation of sales can be technically demanding, especially in mining, if the aim is to use benchmarks to reduce the risk of transfer pricing. The establishment of market value at the mine gate or export point can also be difficult, since it involves 'net-backing' of costs arising from processing and transportation, for

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[12] Hogan, L. (2008). *International Minerals Taxation: Experience and Issues,* ABARE Conference Paper. Washington, D.C.: IMF Media Services Division.

example, from benchmark refined mineral prices. It may be that no international benchmark prices exist on which to base valuation[13].

The above mix of pros and cons has resulted in fairly wide application of royalties in the EI sector but at relatively modest levels. Their relative importance has been greater in the mining sector than the petroleum sector where additional profits taxes may have been introduced. Some countries such as Chile and South Africa have not used royalties for mining for many years, and in oil and gas production, royalties were favoured in North Sea states such as the UK, Norway and Denmark but then abolished or reduced to a zero rating where additional profits taxes are in effect.

To better respond to profitability, many countries, such as Ghana and Armenia, have introduced more sophisticated forms of royalty such as a sliding scale royalty, where the rate is linked positively to production. Depending on how rates and triggers are set, these sliding scale tax instruments, common in the hydrocarbons sector but much less so in mining, can be designed to have a progressive tax take. A sliding scale royalty can also be linked to location. For example, Nigeria has used different rates of royalty, according to whether hydrocarbons production came from on-land, offshore and deep water areas. Other countries have linked progressive royalties to the production and the price (as in Canada), the date of discovery (oil fields/projects or new fields/projects), or to the nature of petroleum (oil or gas), or to some measure of profitability. South Africa uses a profits-based royalty and so does New South Wales in Australia and Peru. Some countries have also included royalty rates as a bidding item in auctions of rights. Sliding scale royalties can nevertheless be difficult to administer, requiring multiple parameters for each mineral. They can also be distortionary, having different effects on different projects.

7.3.5 Bonuses

Bonuses are one-off (or sometimes staged) payments which may be fixed, bid upon or negotiated, and are linked to particular events such as license award or signature, or to the attainment of a particular level of production. They can be part of any fiscal scheme, and provide early revenue, as well as being easy to administer

Signature bonuses, especially when competitively bid, can be sizeable, and as a result have attracted considerable attention in recent years.[14] In 2013 the Liberian National Oil Company announced it had agreed on a signature bonus from Exxon Mobil of US$21.25 million, its largest bonus amount to date. By comparison, high amounts are common in bidding for acreage offshore USA. Much larger amounts can

[13] IMF (2012) lists a number of disadvantages at pp.18-19.

[14] Recent signature bonuses in Angola have been as high as one billion USD per exploration block. Nigeria has also seen a significant increase in signature bonuses. These numbers may be dwarfed by the scale of revenues

be obtained however: in 2007 a consortium of Chinese companies (CMCC and Jiangxi Copper) agreed to pay the Government of Afghanistan a signature bonus of US$808 million and a further US$566 million upon commencement of commercial production. In 2006 Angola received more than US$1 billion as a top bid in its award of rights by a round in 2006.

Bonuses boost the government's take in situations where there is a concern that other dimensions of the fiscal regime may 'leave money on the table;' that is, collect less than the investor is willing to pay. However, they should not be seen as an 'add-on' to an otherwise comprehensive fiscal regime. While that may be the case, it is more general for investors to seek some offset to the bonus through other elements of the fiscal regime. Essentially, the choice of a specific fiscal tool, such as bonuses, involves trade-offs. Once paid, bonuses are neutral in that they have no effect on investment or production decisions going forward. They provide early revenue, and they are certainly easy to administer.

Investor doubts about the value of signature bonuses in a fiscal regime relate primarily to issues of risk. Where there are concerns about a government's commitment to honouring fiscal terms, investors will tend to be very wary about paying out large sums of money up-front on bonuses. This is a sunk cost for companies, recoverable only in the event of successful development of the project. The fact that it is sunk may increase the political risk if the project turns out to be especially profitable. In practice, many governments continue to rely principally on other, contingent fiscal instruments; that is, instruments linked to actual project outcomes while including up-front signature bonuses as a useful complement.

7.3.6 Progressive Tax Instruments

In the extractives sector, a number of different instruments have been used to capture rent. Natural resource rent has been defined as the difference between the market price of the unprocessed mineral above ground and the marginal cost of extracting it.[15] A challenge is to design instruments that do so without making the projects unsustainable when profitability declines. Governments have therefore developed instruments that are 'progressive' in the sense that they capture an increasing share of revenues as profitability rises. These instruments usually are additional to other base-line instruments (and therefore often referred to as 'additional profits' taxes). Such flexible instruments to capture rent are more common in the hydrocarbons sector than in mining, but that imbalance is becoming

[15] Robert Conrad, Zmarak Shalizi and Janet Syme (1990), 'Issues in Evaluating Tax and Payment Arrangements for Publicly Owned Minerals', Working Papers Series 496, The World Bank, Washington DC, p.6.

less marked, as mineral-rich countries seek ways of capturing a larger share of the rent without overtaxing the industry during periods of lower profitability.

One way of achieving this is by means of a so-called 'resource rent' (rate of return) tax,[16] which "targets the returns made on investments that exceed the minimum reward necessary for capital to be deployed"[17]. It gives an investor relief from taxation until a satisfactory rate of return has been achieved, and after that point, it shares profits with the host government on an ex post basis. Dramatic swings in commodity prices have made the resource rent tax topical as a possible means of collecting what have come to be referred to as 'windfall profits taxes' or 'additional taxation.' In their favour it is argued that such taxes do not apply to the normal rate of return to investment in projects, since the government effectively contributes to costs at the same rate as it shares in receipts from production of the resource. As the Henry Report stated, "the government is a silent partner whose share in the project is determined by the tax rate. However, each partner contributes something additional to the partnership – private firms contribute rents associated with their expertise and the government contributes rents associated with the rights to the community's non-renewable resources. These rents are also shared according to the tax rate"[18].

The resource rent tax was first pioneered in Papua New Guinea as long ago as the 1970s and has attracted widely varying responses since then: some highly favourable, others regarding it as inappropriate and unworkable. It is more common today in oil than in mining mainly applying simplified schemes. Typically, it is assessed on cash flow, a different base than that used for income taxes. These bases are quite different (depreciation and finance are, for example, not included in the resource rent tax base). In the resource rent tax, when a hurdle rate is passed (either on a before- or after-tax basis, depending on the structure used) a percentage of cash flow is collected as the resource rent tax. An important consideration for a government in its assessment of any resource rent tax option will be the timing of tax payments, since by design, the allowances permitted will greatly postpone payments until cost have been fully recovered and the specified internal rate of return on the investment achieved.

Controversy has followed the adoption of some taxes: recent attempts to introduce a windfall profits tax in Mongolia and Zambia were withdrawn in the face of strong

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[16] This type of tax is being used in Malawi, Liberia, and Zimbabwe; in 2012 a Minerals Resource Rent Tax was adopted in Australia to tax 30 percent of the 'super profits' from mining companies on coal and iron operations.

[17] Land, B. (2010). Resource Rent Taxes: A Re-Appraisal, in Daniel, P. Keen, M. McPherson, C. The Taxation of Petroleum and Minerals, pp.241-262 at 241.

[18] Australia's Future Tax System: Final Report (the 'Henry Report')(2010): Chapter C: Land and Resources Taxes: http://taxreview.treasury.gov.au/content/FinalReport.aspx?doc=html/Publications/Papers/Final_Report_Part_2/chapter_c1.htm: C-1, p.3.

resistance from the mining industry. Australia's first attempt to introduce a resource rent tax in mining brought about the demise of the Prime Minister. The proposed tax was developed after a government report called for the introduction of a uniform resource rent tax using an allowance for corporate capital system (the *Henry Report*) in 2010[19]. This involved a cash flow equivalent tax levied on profit measured as net income minus an allowance. The latter was designed to compensate investors for the delay in the government's contribution to the cost of investment due to the slower recognition of expense through depreciation and the lack of an immediate refund for losses.

It should be noted that the administration of a rent-based tax is likely to be more demanding than say a royalty or an income-based tax system since it requires the calculation of a profit base that measures rent over time[20]. Detailed accounting procedures need to be agreed upon by the parties to an agreement to ensure that any loopholes or uncertainties in tax administration are eliminated. For countries with limited or very limited capacity in their administrations, this is an important consideration which may encourage them to shift their attention to less ideal but more practical instruments or combinations. For example, simpler cash flow taxes (such as the special tax in Norway) or additional profits taxes and production sharing triggered by the R-factor are becoming more applied.

7.3.7 State Participation

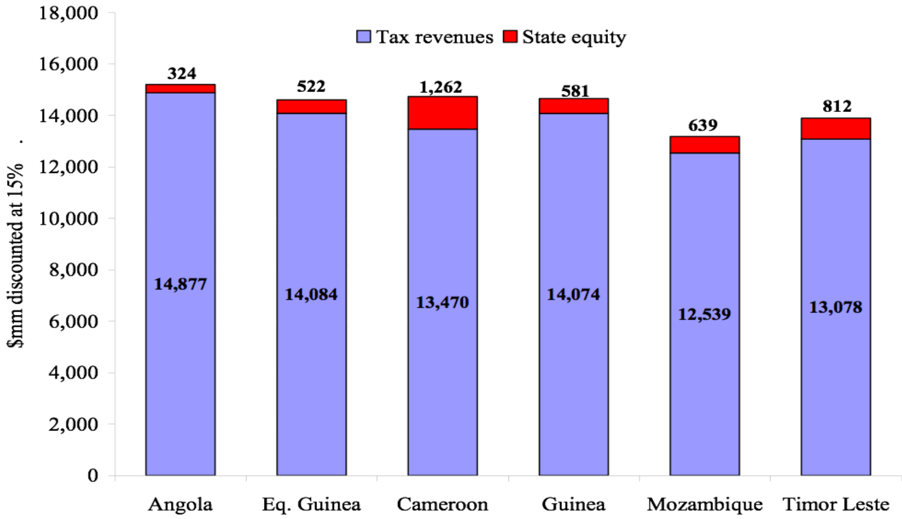
State participation in EI sector projects may be motivated by non-fiscal objectives, such as knowledge transfer, as discussed in **Chapter 5**. However, as typically structured, state participation in EI sector projects will have a fiscal motivation or tax dimension as well. The motivation is participation in profits, especially in their upside potential. The tax dimension depends on how participation is structured. Several forms of state participation can be found in the EI sectors: (1) full equity participation, (2) carried interest participation, (3) free equity participation, and (4) in an indirect way production sharing (see section **Box 7.1** below).

With the exception of free equity participation and production sharing, these forms of participation, full equity participation included, add little to government revenues relative to the application of an efficient tax regime, although they may add considerably to risk. They usually entail some form of offsetting reduction elsewhere in the fiscal regime, resulting in equivalence between state participation and tax

instruments (see the discussion of NRCs in **Chapter 5)**.

[19] Henry Report, Ibid; also Duvall et al (2009), p.242.
[20] Henry Report, ibid.

Figure 7.5: Equity Participation and Efficient Taxation Compared[21]



In each case in **Figure 7.5** government revenues come overwhelmingly from taxation rather than returns to equity participation. Nevertheless, the robust enthusiasm of many governments for state participation, particularly in the hydrocarbons sector, is unlikely to be affected by such considerations. Some investors will continue to favour it too, since in some cases they will only have one government entity to deal with rather than several, bringing operational gains.

[21] McPherson, C. (2010). State Participation in the Natural Resource Sectors: Evolution, Issues and Outlook. In: Daniel, P., Keen, M., and McPherson, C. (eds.). *The Taxation of Petroleum and Minerals: Principles, Problems, and Practice.* London: Routledge, p. 271.

Box 7.1: Forms of State Participation

Governments have embraced state participation in their EI sectors in a variety of forms:

1. **Full Equity Participation.** Two possibilities exist: (1) the state goes ahead without any private sector investment; or (2) the state invests *pari passu* with the private sector from the start of operations, by acquiring either an interest in an incorporated joint enterprise (common in mining) or a participation share in an unincorporated joint venture (common in petroleum).
2. **Carried Equity Participation.** Carried equity participation may take several forms. The most frequently encountered is the so-called 'partial carry.' Under this approach the private investor 'carries' or pays the way of its NRC partner through the early stages of a project – exploration, appraisal and possibly even development – after which the NRC spends *pari passu* with the private investor as under full equity participation. The private investor may or may not be compensated for the funds advanced on behalf of the state, with or without interest or a risk premium. Where compensation does occur, it is typically paid out of the state's interest in the project. A 'full carry' occurs where all costs are borne by the private investor; compensation is paid out of the state's share.
3. **Free Equity Participation.** Free equity participation is a simple grant of an equity interest to the state without any financial obligation or compensation to the private investor.
4. **Production Sharing.** Although not always interpreted as a form of state participation in petroleum countries, in practice production sharing provides the state with a share of the profit petroleum production after cost recovery by the private investor, without any offsetting financial obligation.

7.3.8 Capital Gains Taxes

License or concession interests often change hands; they are often sold from one investor to another. This can serve a very useful function. For example, small companies with an appetite for risk may take on projects with little appeal to major investors. In the event of success, these small companies (often called 'independents' in the petroleum industry and 'juniors' in the mining industry) will look for their reward through transfers or sales of their interest to 'majors' with the financial and technical muscle to exploit the discovery. The transaction often involves the sale of shares in companies that hold mineral rights, rather than a sale of the rights themselves. Such companies are often part of a complex web of cross-border ownership chains. So, any capital gain may be made by a non-resident and be protected by a tax treaty.

Box 7.2: Options in the Treatment of Capital Gains

Three possible approaches to the taxation of gains on license transfers are commonly discussed and exist in practice:

1. **Ignore capital gains in taxing both the seller and the buyer.** This approach is administratively convenient and has the advantage of not discouraging transfers of properties to buyers who are better placed to develop them efficiently. Its principal drawback may be the perceived political cost involved in allowing possibly very large sums, attributable to the states resources, to go untaxed. Norway has adopted this approach successfully, however, having in mind that opportunities exist in the country for re-investment of the gains and provided that the transaction will be on an tax basis neutral, not reducing government revenues.
2. **Tax gains by seller that allows buyer a corresponding deduction.** This approach, applied in Angola, is neutral from a tax paid standpoint. It can, however, produce a significant cash flow timing advantage to the government since the seller's gain is taxed immediately; but the buyer's deduction, if by way of depreciation allowances, is spread over several years. This cash flow advantage to the government represents a loss to the buyer and seller together and could deter transactions meant to rationalize license interests.
3. **Asymmetrical treatment of seller and buyer.** Under this approach, the seller's gains are taxed but the buyer's rights to deduct the cost of the acquisition are either restricted or denied. UK practice provides an example of this. This effectively gives government a further tax slice of the revenues generated by the project. Companies involved in license transfers typically seek to structure transactions to avoid taxation or loss, often by affecting the transfer offshore through affiliated companies and outside the taxing jurisdiction. Government strategies to ensure compliance may include (1) denial of transfer approval until a stamped invoice for payment of tax is presented, or (2) court action to 'pierce the corporate veil' used to conceal transfers.

A large part of the premium, or capital gains, that independents or juniors achieve on such sales (which may be substantial) is rent; nevertheless, depending on the legislation and regulations in place, the investor may be able to structure the sale so that taxation is limited (for example, by transferring interests upstream rather than by a sale of in-country assets when the tax rules are incomplete or unclear). The premiums observed in the last few years have exceeded expectations considerably as a result of dramatically increased prices for petroleum and minerals, and have understandably encouraged re-examination of their fiscal treatment.[22] Much media coverage has been given to the way the issue has arisen in Ghana, Mozambique and Uganda in recent years in both hydrocarbons and mining sectors. The main issues arising centre on these questions: should these gains be taxed and if so, who should or who can tax the gain? Best practice in the design and enforcement of a response is still evolving. Options under discussion and existing in practice are shown in **Box 7.2**.

Capital Gains Taxation (CGT) is becoming more important and more controversial for at least two reasons. First, capital gains are typically much higher due to price increases. Second, CGT is extensively addressed in *developed* countries and the basic principle is that capital gains are taxable. In contrast, in many resource-rich countries outside the OECD area, CGT is either not addressed at all or the tax rules contain so many loopholes that IOCs easily find ways of mitigating CGT. In addition, tax treaty-shopping strategies using tax havens are often used by IOCs when dealing with developing countries to obtain exemption from CGT.

Recent examples of very large capital gains in the extractives sector of developing countries raise an ethical question: why should such profits not be taxable in such countries when they are taxed in most OECD countries? Is it fair to exempt them from CGT? Moreover, when capital gains on oil and gas are indeed treated, this is usually on the basis of concession agreements and is only rarely the case for production sharing contracts (under PSCs two issues have to be addressed: the tax treatment of capital gains and the cost recovery treatment). In practice, CGT has to be treated differently for mining than from oil and gas.

An alternative view of Good Practice would be to recommend that IOCs should usually be subject to CGT, except in some specific cases (such as under farm-outs when the consideration is not cash but only the performance of work obligations). This is however only possible if the tax legislation so provides, specifically for exploration and production. Guidance to governments of such an alternative approach is contained in **Box 7.3** below. In terms of 'fitting' such Good Practice to a particular context, a government may in making revisions to its current tax regime choose to distinguish current or existing investors from future ones in order to ensure that such revisions do not trigger negative perceptions about the stability of its investment climate.

[22] Nahkle, C. (2007). *Do High Oil Prices Justify an Increase in Taxation in a Mature Oil Province? The Case of the UK Continental Shelf.* Surrey: Surrey Energy Economics Centre (SEEC).

7.3.9 Withholding Taxes

Given the typical financing requirements of petroleum and mining projects, and their requirements for special expertise and services not customarily available in the host state, dividend and interest payments and sub-contractor payments to non-residents are common and usually significant. Withholding taxes on these payments – amounts which the company is required to withhold from the above payments and hand over to the state on account of actual or projected tax liabilities of the payees - allows host states to effectively tax this income as there is no practical way to force non-residents to file returns and account for their incomes. Beyond revenue generation, withholding taxes have the additional advantage of discouraging excessive payments to non-residents as a means of shifting profits to lower tax jurisdictions (see **Section 7.4** below). Withholding tax rates on payments to sub-contractors are typically set at relatively low levels, reflecting the fact that they are levied on gross income.[23] Treaties may also cap withholding rates in some cases, which is now a major area of base erosion.

7.3.10 Import and Export Duties

Since there is rarely domestic production of the equipment imported for petroleum or mining operations, the main purpose of import duties in the EI sectors is revenue raising rather than protection of domestic industries. This may be appealing in that it produces early revenues (even before project start-up), but it can also raise costs in the EI sectors and reduce ultimate tax revenues from EI sector production. Nonetheless, even though duties may be included in costs and therefore result in lower taxes paid, the state still receives more as the deduction is worth only a fraction of the duty paid. Recognizing this, most states exempt imports used in petroleum field or mine development from duties, either on a specific list or blanket basis, as an incentive to investors. However, inputs at the production stage may or may not be duty exempt.

Both import and export duties are becoming less important as a source of revenue for most countries due to trade liberalization. Some countries have removed export duties altogether, but others, such as Malaysia, South Africa and Russia impose them on non-renewable mineral and energy resources. The practice has been driven as much by industrial policy as by any of the fiscal objectives listed above, although revenue generation has played a role as well. In many states, governments introduced export duties with the intention of encouraging investment in domestic processing and smelting capacity. In some cases, where local downstream industry

[23] For example, a five percent withholding tax might be levied on payments to subcontractor to approximate a 25 percent income tax on an assumed profit margin of 20 percent.

did develop, the duty was probably unnecessary:[24] the high cost of transporting raw minerals usually provided adequate incentive to domestic processing. Export duties need to be dealt with carefully because they represent another royalty and as such can be (1) distortive and (2) rather than adding value, they may (on a net basis) subtract from it. A legitimate application of export duties will go in pairs with an analysis of the competitiveness of the country in the value chain of the downstream processing.

7.3.11 VATs

Value added taxes (VATs) are levied as a percentage of the value of goods and services, with VAT paid on inputs credited against VAT paid on domestic outputs. Since the EI sectors are largely export-oriented, they have no domestic output VAT against which they can credit their VAT payments on inputs. Relief for EI sector products when exported must come instead from refunds paid by domestic tax authorities. Given the heavy upfront costs and long lead times characteristic of the EI sectors (including the delays experienced in obtaining refunds in countries with weak administrative capacity), this can pose a serious problem.[25]

Many states have resolved this problem expediently by simply zero-rating (as is the practice for export sectors) the VAT from domestic purchases destined for EI projects.[26] However, care should be taken to avoid creating a perverse incentive whereby imports are duty free and local inputs are taxed to the detriment of local producers. Since the overall economic development aim is to see EI sector development stimulating other parts of the local economy (including the provision of local goods and services where feasible and where this is economic), it is important that these types of perverse incentives are avoided.

Some countries have adopted an alternative approach: to provide VAT exemptions for imported capital goods and sometimes imported inputs. This approach, in Peter Mullins' view, is "not considered good tax policy as such exemptions are prone to abuse, complicate administration, and of course, may cost revenue which often has to be recouped from elsewhere in the tax system"[27]. Nevertheless, a specific sector exemption for imported capital goods may be necessary if the tax administration lacks the capacity to administer a refund-based system. It could be limited by project and in time, and to certain capital goods that are necessary to the extractives sector. The overall guideline is that where 'second best' alternatives to VAT are adopted, these should mimic the correct operation of VAT as far as possible.

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[24] See OECD (2010). *The Economic Impact of Export Restrictions on Raw Materials.* Paris: OECD Publishing.

[25] Boadway, supra note 23, at pp. 44-45.

[26] Id.

[27] P Mullins, International Tax Issues, in Daniel, Keen and McPherson (2010), p.397.

7.3.12 Discounted Domestic Sales Prices

In the past, some governments in petroleum producing states (such as Nigeria and Indonesia) have required the sale of at least part of crude oil production to domestic market refiners at discounted, below-market prices. This is essentially equivalent to a royalty and suffers from the same drawbacks as royalties but without the same benefits. The benefits of discounted sales prices flow directly to the domestic refiner, not the government, and represent an opportunity cost loss to the budget. Further, the discounts can be expected to distort domestic investment and consumption decisions with resulting economic losses. The practice of discounted sales at the level of upstream production is now very rare.[28]

7.3.13 Tax Holidays

As their name suggests, tax holidays provide the investor with a temporary reduction or exemption from taxes and duties for a period of years, possibly as long as five to 10 years. When applied, they are used to promote investment based on zero taxation for a specific period. Profits are exempt from tax regardless of their size. Once a common feature in mining sector fiscal regimes, tax holidays are still found in EI but much less well-regarded now. Recent research has been highly critical of their effects, noting that there is little evidence that they have actually encouraged investments, and have generally served to reduce taxes on investments that would have been made anyway, without such an incentive. The result is a net loss to the host state and to distort international competition. An Oxfam study of taxation among developing countries described this as “one of the most damaging tax incentives”[29]. The study noted the potential for abuse: companies that are not eligible for a tax holiday may engage in financial transactions with exempted companies solely to transfer profits from the former to the latter and thereby avoid paying taxes on that profit. It continues:

> “Tax holidays do not encourage a company whose project is long-term to settle in a developing country. It is companies with short-term projects who are attracted by tax holidays, because they are confident that in their first years they will obtain profits, and the tax holiday incentive will exempt them

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[28] Discounted prices at the downstream consumer level, however, are still widespread in petroleum-rich developing countries. Despite their often significant cost to the budget, those subsidies to domestic consumers remain politically very popular and correspondingly difficult to remove.

[29] Oxfam Research Report/Deborah Itriago (2011). Owning Development: Taxation to Fight Poverty. Oxford: Oxfam International, p. 15.

from paying any tax on these. When the incentive ends, they pack up and leave."[30]

Given mining's long exploration and development periods, high costs, low margins, and long pay-back periods, tax holidays were originally promoted and introduced as essential incentives to investment. However, their use in practice has exposed serious investment and operating distortions. Among other things, these relate to the practice of 'high-grading.'[31] Investors were found to be unduly accelerating mine production, focusing only on high margin ores, in an effort to extract as much value as possible before the tax holiday ended. Tax holidays considerably reduced total tax revenues, and in the very worst case, may have resulted in no taxes being paid at all (even though production was highly profitable). Tax holidays have been largely discontinued in favour of less distorting incentives, such as rapid depreciation rates.[32] That said, many countries, including Australia and Canada, provide generous incentives for exploration, including through carry-forward allowances. This can be justified by the fact that the investor will receive only a part (and perhaps a modest part) of the rent once production commences.

7.3.14 Cost Recovery

Cost recovery is an element of various fiscal tools rather than a fiscal tool itself. Cost recovery provisions are critical to assessing any fiscal regime, yet they are often notoriously under-rated in terms of the attention they are given by government in their fiscal design. Investors, however, are well aware of their importance. They are the means by which the investor recovers the costs of exploration, development, and operations from gross revenues. Normally, a PSC will cap the amount of revenues which the investor may claim for cost recovery during a tax period but will allow unrecovered costs to be carried forward and recovered in successive years. Cost recovery provisions include, *inter alia*, a definition of recoverable costs, depreciation rates, cost petroleum limits in the case of production sharing, capital allowances, so-called possible investment 'uplifts,' limits on loss-carry-forwards and an abandonment cost recovery fund. Their detailed specification will have an impact (either positive or negative) on almost every one of the fiscal objectives listed above in **Section 7.1**. Even within the same overall fiscal regime, cost recovery provisions will differ across profit-based fiscal tools. For example, a country using a profits tax and a rent tax will allow different cost recovery for each, generally disallowing finance costs for rent tax purposes but allowing them, to some extent, for profits tax.

[30] Oxfam (2011), p.74.

[31] See for example, the case of Armenia with regard to the adoption of tax holidays. World Bank (2011). *Republic of Armenia Fiscal Consolidation and Recovery*, Background Papers, Report No. 62587-AM. Washington, D.C.: World Bank Publications, p. 9.

[32] ICCM, supra note 181, at p. 47.

The definition of recoverable costs can singularly generate considerable debate. Issues arising include the recovery of: (1) overseas headquarters costs (usually limited as a percent of project costs); (2) interest costs (subject to limits on debt and equity ratios and the application of market benchmarks); (3) costs related to purchases from affiliated parties (addressed by applying OECD rules on transfer pricing or requiring demonstration of third party pricing equivalence); and (4) costs incurred beyond the vicinity of the revenue generating project.[33] The definition of recoverable costs will affect the pace and the size of government revenues.

Provisions related to expensing, depreciation rates, and limits on cost recovery for production sharing purposes have significant implications for the timing of those revenues. The importance of depreciation is that it is an expense deducted from income for tax purposes or as a component of cost recovery under a PSC. Depreciation rules may be different under a PSC for the respective determination of cost recovery and income tax base. Tax depreciation provisions need careful consideration because of their implications for the time profile of tax payments.

Governments can use accelerated depreciation for tax purposes or high cost petroleum limit under the PSC to allow accelerated capital recovery which reduces financial risks for investors. There are risks, however, in allowing investors to achieve rapid cost recovery, with examples in Kazakhstan and Russia of such provisions resulting in a very low share accruing to the host governments under certain PSCs. However, in doing so, governments must fully appreciate that if profits increase sharply due to a mineral price boom, tax payments may not increase until such time as the permitted annual depreciation has been fully utilized. It is possible to envisage that annual tax payments could increase in response to price rises, however, even in the presence of accelerated depreciation. Interactions with loss carry forward rules, for instance, can mean that some share of annual windfalls accrues to government even if assets are not fully depreciated.

Cost recovery provisions are also critical in the areas of environmental and social remediation, and in the restoration of petroleum and mining sites on closure.[34] A number of the cost recovery provisions featured in EI sector fiscal regimes are further discussed in the next section.

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[33] 'Ring-fencing' allowable costs to those incurred on the project itself will reduce incentives to invest in additional exploration or development, but will also avoid deferral of tax revenues.

[34] World Bank (2010). *Towards Sustainable Decommissioning and Closure of Oil Fields and Mines: A Toolkit to Assist Government Agencies,* World Bank Multi-Stakeholder Initiative. Washington, D.C.: World Bank Publications. Available at: http://siteresources.worldbank.org/EXTOGMC/Resources/336929-1258667423902/decommission_toolkit3_full.pdf (last accessed 1 April 2012).

An example of a fiscal package which includes cost recovery in its production sharing is that of Angola (see **Box 7.4**).

7.3.15 Renegotiating and Updating Tax Regimes

While mature states may be able to ensure stable tax regimes, some states experience difficulty in achieving this. States with new EI sector industries, states privatizing loss-making companies, or states recovering from civil war, may make certain tax concessions or provide certain tax incentives in order to attract early investors. If this is the case, then there is a risk that a successor government will demand a renegotiation of the fiscal package if the state's track record in the EI sector becomes more established or stable. In the latter event, a government seeking a change will typically carry out a comparative analysis with peer countries, review its tax regime through a transparent process, introduce flexibility mechanisms such as a progressive tax regime and periodic reviews, and increase its tax rates so that its tax take moves closer to that of states with similar prospectivity. This subject is discussed in some detail in **Section 7.1** above.

In practice, many countries have changed the terms on which their extractive industries operate: Canada, Australia and the UK are examples from the developed economies. Much depends upon the price of the relevant commodity: when prices are high, the tendency is to increase state control and take; when prices are low, the tendency is to reduce it. The resulting uncertainty diminishes the value that investors are willing to pay, motivating a progressive regime. However, if terms have moved out of line with international practice, or in comparable settings, the way is open for a government to consult with investors, and attempt to secure change by means of mutual agreement, with a view to strengthening the investment climate.

The issue is not so much one of whether or not a regime is in general 'stable', but more one of whether a particular regime applying to existing investments is stable or not. For future investments, governments may of course change the applicable terms as they deem appropriate. A second issue is the value of stability clauses in agreements as a defence against unilateral changes or mitigation of their effects.

Box 7.3: Elements for Action on CGT

1. Define the different ways of transferring interests in licences and contracts (because capital gains result from direct or indirect transfers of interests). These are:
   (A) Farm-in/out in a block or contract
   - With only a work commitment as compensation
   - With cash compensation + work commitment

   (B) Sale of a participating interest in a block for a cash consideration
   (C) Sale combining shares in a subsidiary (a direct subsidiary or a subsidiary in a chain of controlled subsidiaries) plus working interest in blocks
   (D) Swaps of interest in licences
   (E) Other forms of transfers: IPO, etc.
2. Address the administrative approval of any proposed transfer, direct or indirect, in particular in cases where the transfer involves a change of control in a subsidiary. Why does such approval require an assessment of the tax consequences of the transfer?
3. Define the capital gain (CG) or profit/loss related to a transfer and the ways to tax such profit, taking into account the following *six* considerations:
   (A) Is the CG considered to be 'ordinary income' subject to normal CIT or at a different rate applicable to CG? What CGT tax rate is applicable when E&P activity is subject to a supplementary tax? How to allocate the transaction cost between several blocks?
   (B) Why should CG be taxed? Why should the value of the transaction take into account the applicable CGT?
   (C) Does the petroleum tax legislation define a special CGT regime for oil and gas E&P? This should normally be the case, especially to deal with farm-in, swap of licences, reinvestment in the country, and so on;
   (D) What are the accounting issues for the transferor and the transferee regarding acquisition costs?
   (E) Is there an impact of the cost of acquisition on cost recovery under PSCs? Should the acquisition cost not be a recoverable cost even when the transfer is subject to CIT?
   (F) How should the impact of favourable double taxation treaties and IOCs' tax planning strategies be mitigated?

Box 7.4: Angola's Fiscal Package for Petroleum

Angola's fiscal regime for petroleum has gone through a number of iterations since oil activity began. However, the package that has now emerged is generally regarded as representing good practice and includes the following components:

1. **Signature Bonus.** Signature bonuses are included as bid items in competitive licensing rounds. Angola's positive track record in honoring contracts and its oil prospectivity have resulted in significant bonuses in recent years.

2. **Production Sharing.** Investors are permitted allowable cost recovery of up to 50 percent to 65 percent of production. Remaining profit oil is split for deep water projects according to a scale which escalates from 20 percent to 85 percent (or from 30 to 90 percent in recent contracts) in the government's favor as a function of the investor's actual achieved profitability.
3. **Corporate Income Tax per project.** A 50 percent tax is levied on the investor's adjusted profit oil share ring fenced per development project. Capital gains resulting from transfers are subject to CIT.
4. **State Participation.** Sonangol (Angola's NRC) equity participation varies from 0 percent to 20 percent (or a higher percentage) depending on the contract.
5. **No royalty payable by the IOC.**

Under these terms, the state's share in benefits is decidedly progressive, while still allowing the investor to share in the upside. The resulting range of government take is consistent with Angola's prospectivity and take obtained in comparable states. Emphasis on profits-based taxation provides an incentive to extended, broad-based development.

Application of the corporate tax allows investors to claim foreign tax credits. Sonangol's equity participation has been kept at relatively modest levels but a higher rate may be provided for in the bidding terms. Angola's decision to seek external audit support has provided protection of its interests in fiscal administration.