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Petroleum Fiscal Regimes in Developing Countries

By Charles P. McPherson

"Building Knowledge on Petroleum Resources Management"

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This paper was prepared under a World Bank contract for the Government of Somalia as part on a broader introduction to key issues related to petroleum sector management and development.

Contents

I. Introduction

Among policy-makers and practitioners the design and performance of fiscal regimes attracts perhaps greater attention and greater controversy than any other aspect of a country's legal and contractual framework for petroleum operations.

Before looking at the specifics of petroleum fiscal regimes, the section immediately following examines a range of sector characteristics that have a bearing on fiscal design. Section III then reviews objectives for any oil and gas fiscal regime, against which its performance might be assessed. Section IV catalogues the instruments available to meet fiscal objectives and discusses their individual pros and cons. Section V looks at how countries have combined fiscal instruments in packages to meet multiple fiscal objectives. Section VI underscores the importance of economic evaluations of existing or planned fiscal regimes and introduces the main parameters and methodologies applied in performing such evaluations. Section VI selects a number of critical fiscal topics for more detailed consideration. The final section summarizes key points and themes.

This paper is concerned solely with upstream petroleum operations, i.e., with the exploration for and discovery of oil and gas, their commercial development and sale, but not with their refining or marketing. Throughout, the term "fiscal" is taken to include all forms of levies on petroleum operations, whether derived from legislation or contractual terms.

II. Special sector characteristics

This short section foreshadows the discussion in Sections III and IV by highlighting special features of the petroleum sector that can be expected to shape fiscal objectives and the choice of fiscal instruments.

Long and costly exploration periods*.* Petroleum exploration, especially in frontier or undeveloped areas, can take an extended period of time before the investor can reach a conclusion as to whether or not a commercial resource exists. The exploration is costly, and in some circumstances may be very costly. This has implications for fiscal design. Once a discovery is made, investors will want to see an early and adequate return to compensate for the long “out of pocket” wait up to that point. Whether or not such a return can be expected is important to attracting investor interest in the first place and will depend in good part on fiscal regime design.

***Exceptionally capital intensive development**.* The typically very high costs of development create additional investor pressure for fiscal regimes that provide and early and appropriate financial returns. Governments may appreciate this investor concern, but at the same time will not want fiscal terms that favor early investor returns to unduly defer revenues to government.

***Captive investments**.* Petroleum discoveries and development projects cannot be moved from one location to another. Investors may be apprehensive that governments, recognizing the captive nature of oil and gas investments once a commercial discovery has been made and successfully developed, chose to revise fiscal terms favorably to themselves. Once again, as a result of this apprehension, investors will seek fiscal terms that allow for early recovery of costs and profits.

***Significant geological, development and political risks**.* Petroleum exploration and development operations come with significant risks…. risks of finding the oil and/or gas, technical risks associated with development of discoveries, risks of unanticipated delays, risks of cost overruns. Investors can be expected to bear these risks but they will expect fiscal incentives in return. Political risks, - risks of political disruptions, unilateral revision of fiscal terms, etc. – may also represent a challenge to investors which they will seek to see reflected in the incentives offered by the host country. These are risks, however, that the host government may be in a position to mitigate. To the extent they are successful, terms offered to investors may be more aggressive in government’s favor.

***Volatile prices**.* Oil prices are notorious uncertain and volatile, with major implications for fiscal design. Government will want to capture the lion’s share of significant price-driven revenue increases, while investors will want some protection of their profitability when prices tumble.

Variable qualities, products and prices. Crude oils may differ greatly in quality – specific gravity, sulphur content, waxiness and location relative to market. And crude oil operations differ in a number of important respects from natural gas operations – elapsed time to commercial marketing, typical profit margins, processing and infrastructure requirements. These differences ought to be recognized in the elaboration of any petroleum fiscal regime.

***Resource depletion**.* The inevitable exhaustion and eventual depletion of a petroleum resource raises a number of fiscal issues. For one thing, unit costs tend to rise and margins fall as production declines. Fiscal terms will have to adapt to these changing circumstances if incentives to produce are to be maintained.

***Environmental concerns**.* Costs of maintain environmental safeguards during petroleum operations and of restoration after operations are abandoned are significant. The fiscal regime should provide for recovery of these costs. This presents a particular challenge in the case of abandonment costs when the revenue against which costs might have been recovered has ceased.

***High political profile**.* Significant revenues (actual or anticipated) increase the risks of populist and political interference on petroleum fiscal design.

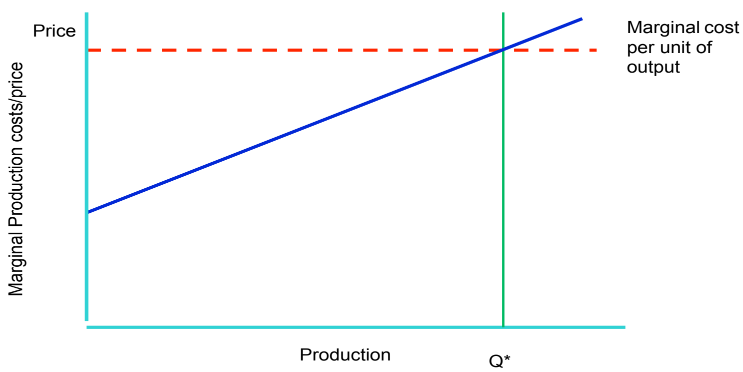
III. Fiscal regime objectives

The design, assessment or redesign of any oil and gas fiscal regime should begin with a discussion, ideally multi-stakeholder, of desired regime “deliverables”, i.e., of regime objectives. The following list is non-exhaustive, but does include those objectives most commonly identified by policy-makers:

***Efficient production and broad-based development**.* As nearly as possible, fiscal regimes should encourage the investor to produce a field or reservoir up to the point where “all-in” unit costs are just matched by unit price. All-in costs include not only direct out of pocket costs but also “external costs” such as those that might be inflicted on the environment, and the investor’s own minimum return on capital. What is meant by efficient production at the field level is illustrated in **Figure 1** below. The vertical axis measures unit cost and/or price; the horizontal axis, production. The blue line shows unit costs rising with production; the horizontal red line shows the price level provided by the market. Field production is efficient at the level Q*, where price just covers cost. Ideally the fiscal regime should encourage production up to the Q* level.

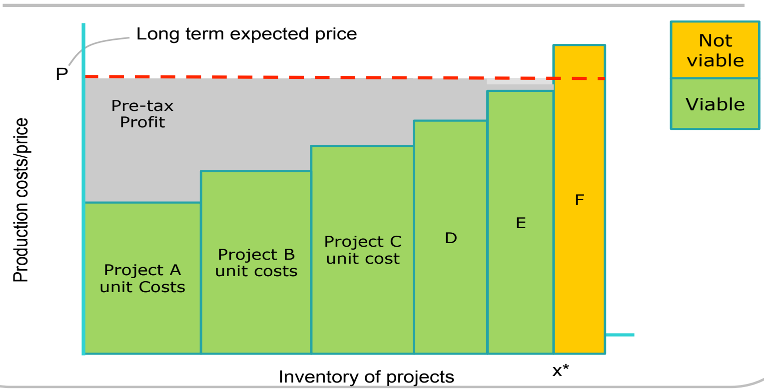
The same argument can be made at the level of the sector overall. Broad-based development should see development of all those existing or potential projects whose marginal cost is just covered or more than covered by long term expected price. See **Figure 2.** Projects A through E all meet this criterion and should be

Figure 1
Efficient Field Production



encouraged by the fiscal regime. They are all viable pre-tax and should ideally remain viable after-tax. Project D does not meet the criterion. It is not viable pre-tax

Figure 2
Broad-based Development

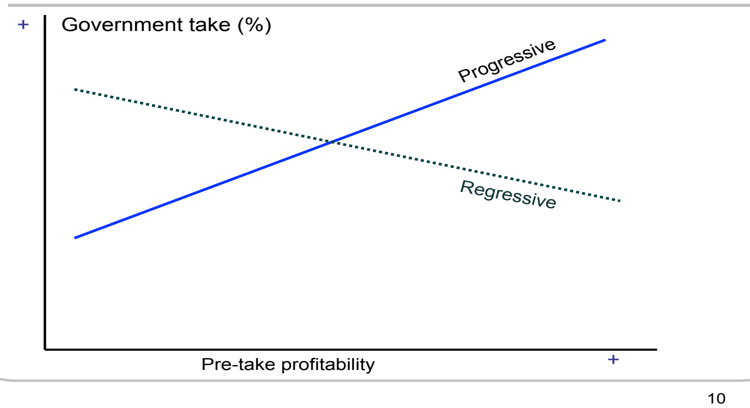


and should remain non-viable after-tax.

The fiscal outcomes illustrated here at the individual field (Figure 1) and sector (Figure 2) levels are generally referred to as socially optimal. Other things equal, fiscal regimes should be designed to result in minimal distortions of these outcomes.

Progressive state capture of rents. The area between cost and price in Figures 1 and 2 represents rents – revenues in excess of what is required to recover cost including the investor's minimum required return. Rent is the "pie" which is shareable between government and the investor. An important objective for governments is to capture as much as possible of this rent, and to capture an increasing share of it as it increases. A fiscal system that accomplishes this is known as "progressive"; a regime that produces the opposite or perverse results is known as "regressive". Stylized versions of the two opposing outcomes are shown in **Figure III.** The state's/ government's share of rents, typically referred to as its "take " is measured along the vertical axis; pre-take project profitability is measured along the horizontal axis, increasing from left to right.

Figure 3
Progressive State Capture of Rents



The rising blue line represents a progressive fiscal regime; the dotted black line a regressive regime. The slope of the line for any fiscal regime will depend on the mix of fiscal instruments that make it up, and the progressive or regressive character of each component instrument.

Cost containment. The lower costs are, the larger the size of the pie to be shared between government and investor. Fiscal regimes ought therefore to encourage cost consciousness.

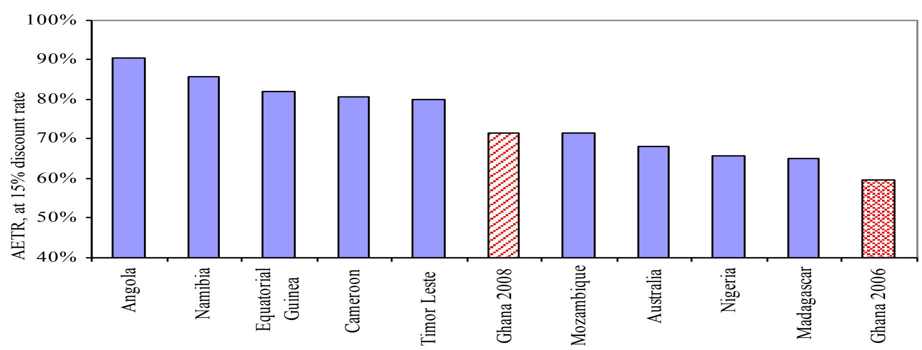
Early revenue. Investor interest in early revenue has already been noted. Governments share that interest, especially in low-income developing countries where demands on funds to meet poverty alleviation needs and address underfunding of critical social and physical infrastructure have become urgent. In countries where development of the petroleum sector is just getting underway, timing of sector revenues will depend in good part on the specification of fiscal terms.

Dependable revenue. Governments also place a premium on dependable revenue. It may be impossible to expect a steady revenue stream, but governments do want to see some revenue coming in under all circumstances once commercial development commences.

Risk management. Geological, technical and political risks, their implications for the level of fiscal incentives offered to investors and the comparative advantages of investor and government in managing them were discussed above. Another risk to be managed relates to revenue volatility. Arguably, the investor, whose portfolio of projects is likely to be much more diversified than that of a new petroleum producer should be well placed to accept this risk. In practice, however, political and budgetary pressures on host governments to capture the upside of any boom-bust revenue cycles often leads them to accept a large part of the revenue volatility risk.

International competitiveness. Petroleum projects may be immoveable once established, but prior to that moment the capital required to support them is very mobile, generating a competition among existing and potential petroleum producing countries to attract that capital. Geological potential along with the host country fiscal regime are often central to determining the outcome of such competitions. **Figure 4** provides an example of the comparisons that a petroleum company investor might make in the process of deciding where to place its money. The same comparisons might be generated by a host country to assist in determining whether its take is too high or too low relative to that of other countries seeking the same investors. The vertical axis indicates the average effective tax rate applied to a hypothetical oil field development in a selection of countries shown along the horizontal axis.

Figure 4
International Competitiveness (Oil)
Selected Countries



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***Simplicity of administration**.* Weak institutional capacity is a major issue in many, if not most, developing countries. This can be an acute problem when it comes to administering petroleum fiscal regimes, leading countries to opt for simplicity in fiscal design at the expense of sophistication. Simple fiscal regimes can bring their own problems, however. They may distort incentives and/or fail to perform as hoped under changed circumstances, leading to tension between governments and investors and creating pressure to renegotiate terms.

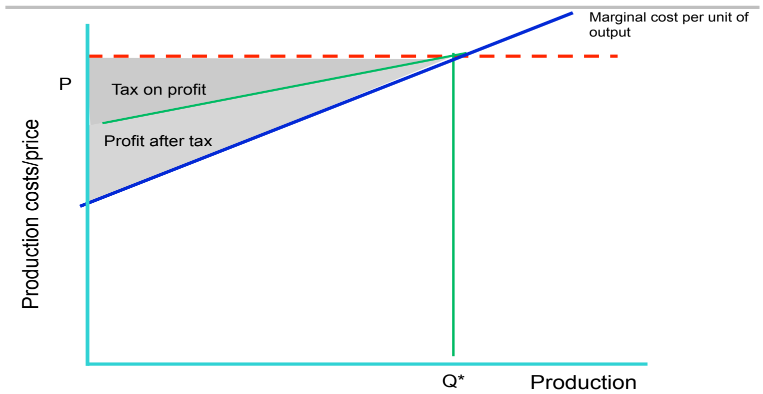
IV. Fiscal instruments

Multiple fiscal objectives typically call for multiple instruments, each of which may bring particular attributes, positive or negative, to the overall fiscal regime. This section reviews the fiscal instruments most commonly applied to petroleum operations and assesses their merits and drawbacks against the objectives set out in Section III.

***Profits taxes**.* Profits taxes include generally applicable corporate income taxes or income taxes applied specifically to petroleum, and any other levies based strictly on profits. They are expressed as a percentage of revenues minus costs. Profits taxes are usually in the range of 35 to 50 percent.

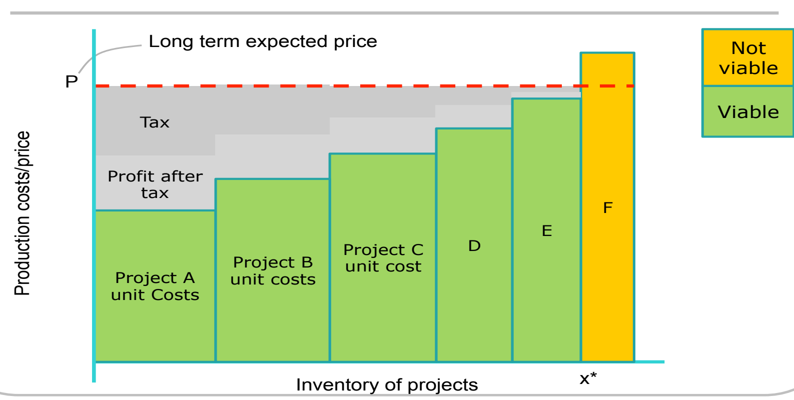
The principal appeal of profits taxes lies in the fact that they have minimal distortionary impact on investors' decision making, at either the individual field level or at the level of the petroleum sector overall. Production or investment decisions which are viable or attractive to the investor pre-tax will be viable post-tax as well. This is because by definition the tax takes only a specified percentage of available, positive pre-tax profits of rents, always leaving something for the investor. This point is illustrated in **Figures 5** and **6** which overlay Figures 1 and 2 with an assumed profits tax.

Figure 5
ProfitsTaxes and Efficient Production



The shaded area in each figure - the space between price and cost – represents profits or rents. Deeper shading represents the profits tax. Because the investor continues to receive a share positive income right up to the point where positive income ceases, he will be encouraged to take field production up to the optimal level, Q*, in Figure 5, and to pursue project development through to and inclusive of E in Figure 6.

Figure 6
Profits Taxes and Broad-based Development



Profits taxes have mixed scores when assessed against other fiscal objectives:

Without modification, e.g., introducing tax rate scales, they are not progressive. The percentage they take of profits or rents is constant – it does not increase as profitability increases.

They do encourage cost containment because any increase in profits as a result of cost savings will be shared between the investor and government.

Profits taxes do not score well against early and dependable revenue criteria however. To the extent that profit taxes allow early recovery costs by the investor they will reduce government revenues at the beginning of a project deferring them until later in the project's life. Further, the timing and scale of government revenues in any one time period will be uncertain depending on the time profiles and scale of revenues and costs.

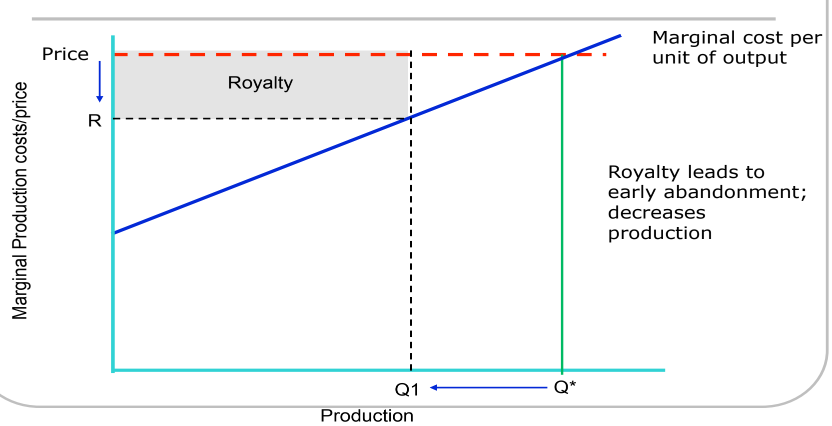
In terms of investor perceptions, profits taxes are welcome for several reasons. Their efficiency and tendency to promote broad based sector development is one. Secondly, until recently international investors were unable to claim payments to the host country as credits against tax obligations in their home countries unless they were subject to an income tax in the host country. Third, the "optics" of a profits tax, such as the generally applicable corporate income tax, are appealing insofar as they allay popular suspicions of favourable treatment petroleum of investors.

Complexity of administration is the most common argument against profits taxes. The perceived complexity relates primarily to accounting and audit procedures. Governments have expressed concerns that weak institutional capacity in these areas has led to significant revenue losses.

Royalties. Royalties may be specified as a fixed charge per unit produced or *ad valorem*, as a percentage of revenue generated per unit. Rates for the latter typically range between 10 and 12 percent.

The main drawback of royalties is the reverse of the principal advantage of profits taxes. Depending on their level, they can be highly distortionary of investor incentives and result in well below optimal levels of production or sector development. **Figures 7** and **8** once again redraw Figures 1 and 2, this time showing the impact of a royalty.

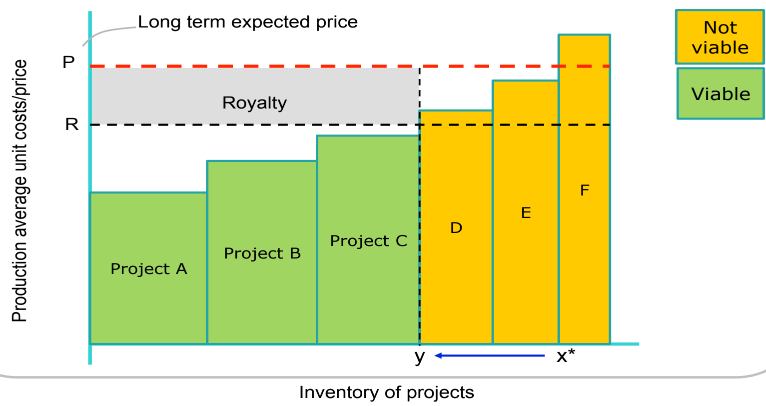
Figure 7
Royalties and Efficient Field Production



The royalty represented in the two figures is an *ad valorem* royalty. By taking a percentage of revenue "off the top" it effectively reduces the price to the investor from P to R in the figures. In the individual field case shown in Figure 7, the consequence is a reduction in the level of production from the optimal Q* to Q1. Q1 is the new level of production at which price as perceived by the investor, just covers cost . The parallel result at the sector level, shown in Figure 8, is a reduction in the number of commercially viable projects from A through E pre-royalty to A through C post-royalty. The severity of this negative impact will depend on the scale of the royalty and the cost profile of production – the slope of the blue line in Figure 7, and the stacking of project costs in Figure 8.

A related serious drawback of royalties is that they are regressive, rather than as desired, progressive. As a result of the royalty's insensitivity to cost and

Figure 8
Royalties and Broad-based Development



profitability, the government's royalty take decreases rather than increases as cost in creases and profitability increase. **Table 1** provides a numerical example.

Table 1
Royalties Are Regressive

	Calculation	Low Cost High Profit	High Cost Low Profit
(1) Gross revenues		100	100
(2) Cost		40	60
(3) Pre-tax margin	(1) – (2)	60	40
(4) Royalty (10%)	0.10 x (1)	10	10
(5) Royalty as % of margin	(4) / (3)	16.7	25

Assuming the revenue and cost numbers shown in the table, a 10 percent royalty results in a 16.7 percent take of the profit margin in the low cost, high profit case, while the same take in the high cost, low profit case is 25 percent. This kind of perverse behavior will lead to premature abandonment of fields as production costs rise and at the sector level to the neglect of marginal, higher cost projects that might otherwise have been viable.

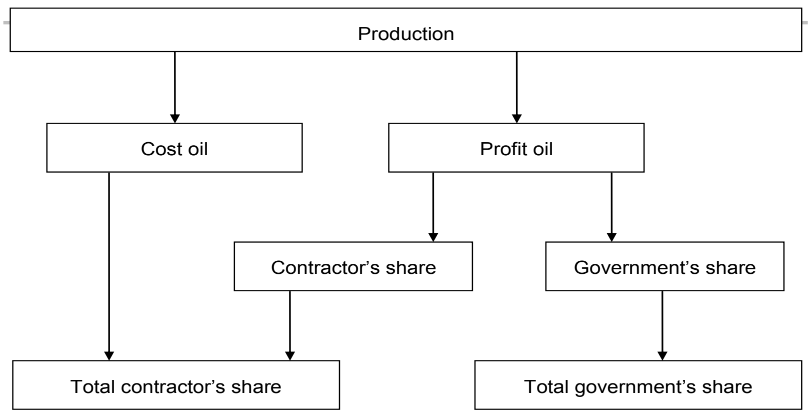
These reservations notwithstanding, the royalty remains an important component of many fiscal regimes and for a number of reasons:

For one thing, in contrast to profits taxes the royalty provides revenue to the host government from Day One of production and the revenue is dependable as long as there is production. Provided the royalty is set at reasonable levels, investors appreciate these features as much as host governments. Being able to demonstrate early payments to the host country, even if at relatively modest levels, makes for "good press".

Secondly, again compared to profits taxes, royalties are seen as easy to administer and less demanding on the capacity of host country revenue authorities. This may be partly true, but the negative efficiency and developmental consequences of a heavy reliance of royalties need also to be kept in mind. A compromise approach, commonly found, relies of profits taxes for their efficiency, and a royalty element for its positive features. This approach would ideally be complemented by a program of capacity building in the revenue authority.

Production sharing. Production sharing is a very popular contractual and fiscal framework for petroleum operations, particularly in developing countries. It is well understood and widely accepted by international investors. Its fiscal dimensions combine elements of both profits taxation and royalty.

Figure 9
Production Sharing Schematic: Base Case



Under production sharing a fixed percentage of gross production is set aside for recovery of the investor's costs ("Cost Oil"). The remaining production ("Profit Oil") is shared between the government (or its agent) and the investor on a percentage basis agreed or negotiated between government and the investor. The sharing of Profit Oil is akin to a profits tax. The fixed percentage limit on cost recovery in any one accounting period guarantees a minimum payment to government regardless of actual costs or margins and so is akin to a royalty. Because of its hybrid nature it shares both the positives and negatives of the profits tax and the royalty. **Figure 9** above presents a simple schematic illustration of basic production sharing.

Cost recovery provisions. Although not generally thought of as fiscal instruments in the way that profits taxes, royalties or production sharing are, the cost recovery provisions of any petroleum fiscal regime can have major implications for fiscal outcomes and for the assessment of a regime against fiscal objectives. Critical provisions include: the definition of allowable costs; the treatment of payments made to affiliates; rules for expensing and/or depreciation of costs; rules governing the consolidation of costs for recovery; and procedures for the recovery of abandonment costs. Several of these provisions are considered in more detail under **Special fiscal topics** below.

Bonuses. Bonuses are one time payments by the investor tied to specific events or the achievement of certain milestones such as license signature, declaration of commercial discovery, and/or attainment of a certain level of production. Bonuses may be bid, negotiated or fixed. In recent years bid signature bonuses have received the most attention and under the right circumstances can reach substantial levels.

Signature bonuses are incurred before operations begin. They are "sunk costs" and as such will have no effect on the investor's decision making going forward. They will not interfere with efficient production or distort the extent of project development at the sector level.

Bid signature bonuses contribute to rent capture. The scale of the bid will depend on the investor's expectation of the project rents available in the event of success. In that sense bid bonuses are also progressive – the greater the expected rent or, the greater the bonus will be. The government's share increases as profitability increases, only in this case profitability is perceived profitability, not actual profitability.

Clearly signature bonuses meet the government's early revenue criterion. Unfortunately, in some cases where a government's need for cash is acute, this attribute may drive the licensing process at the expense of attention to other features of the investment framework, fiscal or otherwise.

Investors are tolerant of signature bonuses if they are kept at reasonable levels. What constitutes a reasonable level will depend on geology, other elements of the legal and fiscal regime, and perceptions of political risk. Just as they may be concerned about investing exploration and development monies upfront where there exists the possibility of unilateral negotiation of terms by government, so investors may reluctant to bid an upfront bonus that reflects the true value of the resource. Bonuses are almost invariably only part of a fiscal regime; typically they are paired with other fiscal instruments that link government take to actual rather than expected outcomes.

Flexible rent capture mechanisms. Each of the fiscal instruments discussed above is intended to capture a significant portion of petroleum project rents for the government or state. Rents or profitability are going to vary, however, from project to project, and from one time period to another, reflecting differing geological success, and price variability. Other factors include: differing values for different production characteristics; differing operating conditions and costs; differing times to commercial production; and differing production profiles. The challenge for the architects of a petroleum fiscal regime is to design a regime that will adjust automatically to these variations. Absent an automatic adjustment mechanism of some sort, either there will calls from the host government for revision of the regime or pressures from investors for renegotiation of terms to correct perceived inequities or distortions of incentives.

In practice, a number of mechanisms have been introduced to in an attempt to introduce fiscal flexibility. These commonly involve linking one or more fiscal instruments (tax, royalty, production share, additional tax, etc.) to easily observed proxies for project profitability. Alternatively, the fiscal instrument may be linked to profitability itself. Examples are listed below:

- Government's production share is a function of cumulative or daily rates of production
- Royalties escalate with price
- Government take escalates once investment or a multiple thereof has been recovered
- Government take is tied to the location of production operations, the type of hydrocarbon or the vintage of production
- Take escalates with a financial ratio such as taxable income to revenue or cumulative receipts to cumulative outlays (sometimes known as the "R-Factor")
- Government take varies as a function of achieved profitability measured by the investors achieved rate of return (ROR)

The problem with using proxies for profitability to introduce fiscal flexibility is just that – they are proxies. They are partial, often inaccurate measures of profitability and are likely to become quickly outdated. Their apparent simplicity is often misleading. Their inaccuracies and lack of completeness often result in result strains on fiscal regime stability, changes in terms, increased investor perceptions of risk and demands for fiscal stabilization, and expansion of the complexity of the regime.

Table 2 summarizes the fiscal regime under consideration in one of the draft versions of a planned new Petroleum Industry Bill in Nigeria. An effort to have the regime respond to different circumstances and at the same time a recognition of the shortcomings of different proxies for profitability led to a highly complex proposal which almost certainly would fall short of its goal and would prove an administrative nightmare.

Table 2
Nigeria's Proposed Petroleum Industry Bill:
Bells and Whistles

- Royalties are a function of:
  - Price
  - Production rate
  - Type of hydrocarbons
  - Location (water depth)
- Production sharing is a function of:
  - Production
  - Location
- Tax regime varies with
  - Location
  - Type of hydrocarbons
  - Field size

Table 3 provides a tabular comparison of the effectiveness of various rent capture mechanisms in producing a system of government take that is fully responsive to all of the critical determinants of project profitability. For example, reading from the table, linking government take to daily or cumulative levels of production responds to the influence of production on profitability, but it misses out on responsiveness to other influences, e.g., price and cost. Linking government take to price captures the influence of price on profitability, but misses out on production and cost. And so on.

Table 3
Responsiveness of Rent Capture
Mechanisms to Determinants of Profitability

	Government "take" responsive to:				
Government "take" linked to	*Production*	*Price change*	*Costs*	*Timing of cash flow*	*Cost of capital*
Production (daily or cumulative)	**Yes**	No	No	Partly	No
Price (price caps or base prices)	No	**Yes**	No	No	No
Cost recovery (uplifts and write-off rates)	No	No	**Yes**	Partly	Partly
Simple indicators (location, vintage, and so forth)	No	No	Partly	No	No
Financial ratios (e.g., taxable income to revenue)	**Yes**	**Yes**	**Yes**	No	No
Rate of return (ROR)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

It is only when the rent capture mechanism is liked profitability itself, measured by the investor's actually achieved ROR that it results in a system of government take that is fully responsive all determinants of profitability. Focus on this one linkage has the additional advantage of obviating the need for all the "bells and whistles" included in the Nigerian proposal summarized in Table 2.

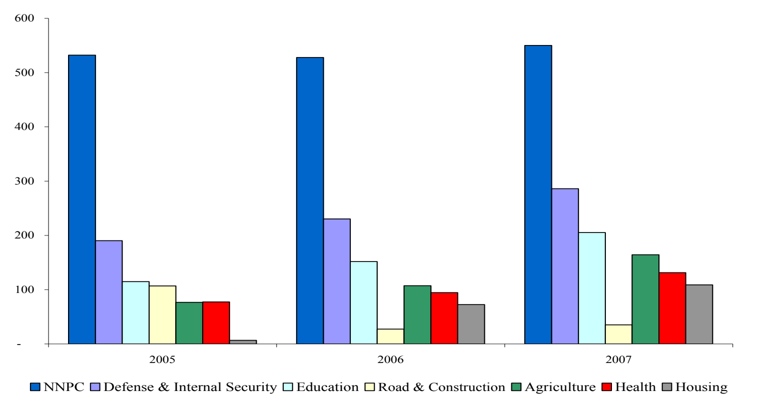
Arguments in favour of the ROR approach are powerful. It is squarely focused on excess profits or rents and as such does not distort the investor's decisions regarding optimal levels of production or project development. By definition it is progressive. Because it is based on actually achieved profitability the approach can potentially facilitate negotiations and reduce investor demands for fiscal stabilization.

The principal objection to the ROR approach is that in practice it will turn out to be too complex to administer. In fact, it is only marginally more complex than ordinary profits tax or production share calculations and data requirements for implementation and administration are the same. Because additional charges under the ROR approach only kick in once a threshold return has been breached, government revenues are necessarily deferred. This can be compensated for by twinning the ROR instrument with another front-loaded fiscal instrument such as a royalty.

State participation. Petroleum legal frameworks very commonly provide for state participation in petroleum operations. A number of options exist, all except one of which have fiscal connotations.

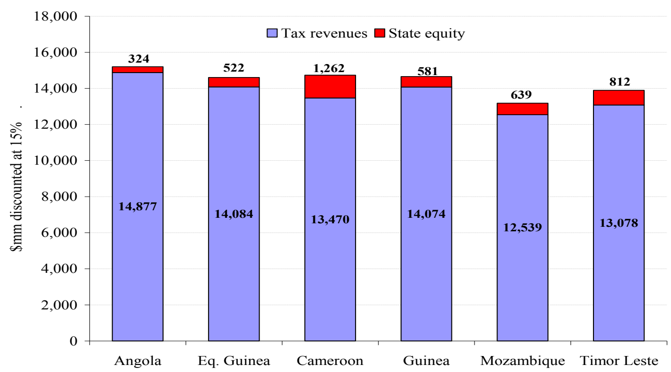
Full equity participation requires that the state participate *pari passu* with its private sector partners in all risks, costs and revenues from the beginning. There are no fiscal connotations. There are serious implications for the state in terms of risk acceptance and funding obligations, however, which explains the relative rarity of this form of participation. It is practiced on a limited scale in Nigeria, Angola and Indonesia.

Figure 10
Competing Budgetary Allocations in Nigeria



Apart from non-economic drivers, e.g., creation of national capacity, full capture of rent attributable to the government's participation share is an often encountered argument for full equity participation. It should be borne in mind, however, that this not comes with substantial funding requirements and the risking of public funds that might be beneficially directed elsewhere, e.g., to building physical and social infrastructure, but also that an efficient fiscal system can be nearly as effective in capturing rent. **Figure 10** above shows, for budget years 2005-2007, the sharp contrast between the funding required to support Nigeria's full equity participation in oil and gas activities through it national oil company NNPC and the budgetary allocations to other critical economic and social sectors. **Figure 11,** prepared for a number of different country fiscal regimes, illustrates the point that the lion's share of government receipts from petroleum projects typically comes from the tax regime, with only a small additional amount to be gained through full equity participation.

Figure 11
Equity Returns vs. Tax Revenues



Much more common than full equity participation is the so-called "carried interest" approach to participation under which the investor funds the government's share of costs and is repaid with interest out of the government's participation share in profits. The "carry" may extend only to exploration and appraisal costs, or it may extend through development costs. The fiscal equivalent of this approach is the ROR-based rent tax – the investor puts up all the funds and is allowed to recover an agreed return before the government begins to collect its fiscal share.

A third option is free equity participation. The government is assigned a free share in project cash flow that is equivalent to a cash flow or dividend tax. Production sharing is a form of free equity. It assigns a free share in project cash flow, but also adds a role in project management that other forms of free equity participation may not do.

To the extent that the participation formula adopted by the host country has a fiscal dimension, potential investors will take this into account, possibly demanding terms less favourable to government in other fiscal areas to offset the impact of participation.

V. Fiscal packages

Multiple fiscal objectives require multiple instruments. As a consequence petroleum fiscal regimes invariably consist of packages of instruments. The most common packages are the tax-royalty and production sharing regimes.

The tax-royalty regime typically comprises a base income tax (generally the corporate tax of general application n the host country), a modest *ad valorem* royalty and an additional profits tax to serve as a progressive rent capture mechanism. It may or may not include a mechanism for state participation. While traditionally associated with developed country regimes, the tax-royalty formula is found in a number of developing countries as well.

Production sharing regimes comprise standard cost recovery and base production sharing terms along with, in pursuit of fiscal progressivity, an escalation of shares in government's favour as a function of production. A royalty may or may not be explicitly added. State participation is optional. In addition to the production share, the investor will be liable to payment of corporate income tax based on revenues received from Cost Recovery and Production Shares under the Production Sharing Contract less cost deductions as allowed under the general Corporate Income Tax or a separately specified Petroleum Income Tax. **Figure 12** repeats Figure 9 with the addition of a royalty and income tax. Developing countries have shown a preference for Production Sharing largely based on sovereignty and non-economic issues.

Figure 12
Production Sharing Schematic with Royalty and Income Tax

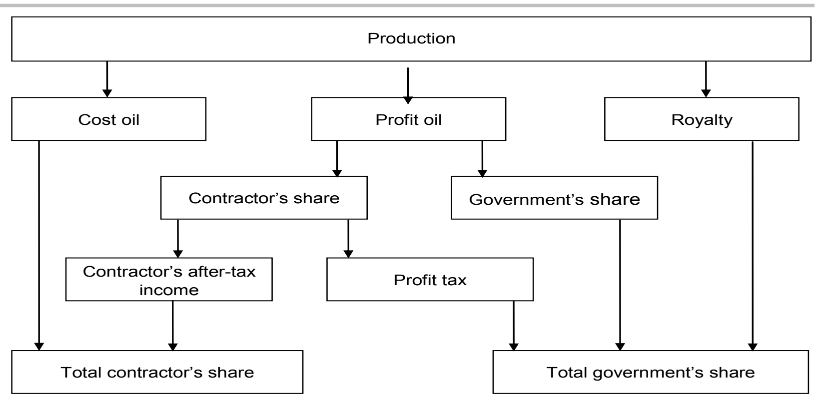


Table 4 is indicative of the range of fiscal packages adopted in a selection of petroleum producing countries. In some cases a country may have more than one regime operating at the same time.

Table 4
Fiscal Packages: Indicative Practice

Country	Tax/Roy	PSC	Service	Participation
Algeria	X	X	X	X
Egypt		X		
Libya	X	X		X
Morocco				
Sudan		X		X
Tunisia	X	X		
Angola	X	X		X
Indonesia		X		X
Norway	X			X

It is fundamentally important to recognize that at the fiscal level all of these approaches can be made equivalent. What is essential in designing or comparing fiscal regimes is to go past the label – tax/royalty of production sharing – at look at the detailed specification of the package in terms of structure and numerical parameters.

VI. Fiscal regime evaluations

Why evaluate? Initial and continuing evaluation of petroleum fiscal regime is critical to its efficiency and effectiveness. Routine evaluations can serve a variety of important purposes.

The first of these is in the initial design of a country's fiscal regime. The evaluation will help in the selection of a regime that best suits the country's needs or aspirations. Subsequent evaluations can identify any need, if any, to revise or update the regime in the light of changed circumstances. This exercise will be particularly appropriate going into the preparation of any new licensing round. Once the round has been announced, and prospective licensees have been identified, the ability to quickly assess proposals made during negotiations will depend on a working fiscal evaluation model.

Further down the road, once exploration and appraisal operations have identified a commercial discovery, the host government may rely on an evaluation model to determine whether or not to exercise an option to financially participate in the development and exploitation phases. With or without participation, simulations using such a model can be a significant help in economic planning at both the sector and macroeconomic levels.

Finally, when evaluations are conducted at the project level they may provide a useful check against fiscal audits. A large gap between audit findings on payments made and what the evaluation says should have been paid should raise a flag and suggest a need for further investigation.

What to evaluate? Fiscal regimes can be evaluated at a number of levels. Their impact can be assessed at the individual project level, on either a full cycle basis (exploration through development and production) or on a point-forward basis (e.g., starting with development). Project level results can be aggregated across projects to obtain results at a sector–wide level.

One of the most useful evaluation exercises is scenario building. Critical assumptions on price, production, costs, or timing can be changed to "shock" the assessment and produce "what-if" results for different scenarios. Sensitivity analysis of this kind is vital for responsible economic planning.

Evaluation criteria and indicators. The starting point in any evaluation exercise is agreement on evaluation criteria. These may be various, but the list of fiscal regime objectives discussed in Section IV above is representative. Can the regime be expected to encourage efficient, road-based development? Will it prove effective in capturing rents? Is it progressive? Will it promote cost containment? Early and dependable revenues? What does it imply for risk sharing between the investor and government? Is it internationally competitive?

Each of the evaluation criteria should be matched with an indicator or indicators to help measure performance. The investor's simulated project ROR and the percentage government take are widely used to assess regime performance against objectives. Investor ROR is the after-government-take internal rate of return realized by the investor. A number of different measures of government take can be found in practice, but the correct measure is the present value of all payments to government divided by the pre-take net present value of project cash flow.

For example, the two indicators are frequently used to assess the likely impact of a fiscal regime on production efficiency and the margin of development. The same two indicators, can also test for progressivity when calculated for a range of underlying project profitabilities. If the regime is progressive, the investor's ROR should rise as project profitability rises, but at a decreasing rate. The government's rate of take should also rise as profitability increases. Calculated across different country fiscal regimes, the government's rate of take can help in answering the question of the international competitiveness of the host country regime. Figure 4 above compares simulated percentage government take in different countries with this in mind.

Government and contractor cash flow streams produced by an evaluation model can inform policy makers on the likely timing of cash flows, and the sharing of cash flow volatility risk.

Evaluation model requirements. Successful evaluation modeling depends critically on credible input data: prices (past and future scenario assumptions); production; cost (both capital and operating costs). The data should be made available by license or field. Fiscal terms (both those provided by legislation and those contained in the contract or license) should also be available by contract or license area. These will allow specification of the model, and, when combined with data inputs, the looked-for evaluation outputs.

To be useful the model should be regularly updated. Effective modeling will require inter-agency coordination, specifically among the sector ministry, the regulatory agency, and the national oil company if there is one. Close cooperation with users of model outputs, e.g. the finance ministry, revenue administration authorities and the planning ministry, will be important in realizing the full potential value of the model. Finally, ensuring the requisite institutional capacity – skills and resources – is in place and maintained is essential.

VII. Special fiscal topics

This section looks at a non-exhaustive selection of special topics that commonly arise in the context of petroleum taxation; fiscal prices; cost recovery issues; withholding taxes and double taxation treaties; taxes on transfers of interests; and fiscal stabilization.

Fiscal prices. These are the prices used to determine the investor's payment obligations, i.e., for income taxes, royalties, production sharing. Governments are understandably reluctant to simply accept the price the investor suggests should apply, particularly when the transaction in question is between affiliated parties.

Where oil prices are concerned governments may accept the price provided by the investor if it can be satisfactorily demonstrated that the sale was between non-affiliated parties. More commonly, governments now use international reference prices. These are well established market-based prices continuously quoted and published for particular widely traded crude oils. North Sea Brent, Nigeria Bonny Light, West Texas Intermediate, and Indonesia Minas are classic reference prices. Once a reference price is selected and agreed, it is adjusted for differences in costs of transport to market between the reference crude oil and the host country crude oil, and for any differences in the quality of the two crude oils (specific gravity, waxiness, sulphur content) that may have a bearing on value. As with the reference price itself, adjustment factors are regularly published and readily available. This approach avoids possible revenue loss and avoids disputes with investors. It is widely accepted by investors.

Arriving at a fiscal price for natural gas is more difficult. This is because, in contrast to oil, gas markets with the exception of the United States and increasingly Europe, are not well developed and quotes on prices are not continuously or readily available. Further, natural gas is often commercialized through an integrated system, e.g., involving field development, local processing, transport by pipeline or ship (in the case of liquefied natural gas or LNG) and further processing (e.g. LNG re-gasification) at the final destination. Pricing arrangements under such circumstances are typically confidential. To get at or set a fiscal price for natural gas governments have three options: (1) estimates of the price required to recover costs and an acceptable investor return at the well-head or field exit point; (2) calculation of a net-back priced based on observation of prices at the final end-use market point and deduction of costs to get to market; or (3) reference to the price of principal alternative fuels, e.g., heavy fuel oil in the power market.

Cost recovery issues. The design and implementation of rules for the investor's recovery of costs can have very substantial consequences for the bottom line impact of a fiscal regime on government revenues. Unfortunately, these topics attract far too little attention compared to the attention paid to rates of taxation or production sharing or royalty levels. The relevance of policy decisions taken on which costs can be expensed, and which must be depreciated and at what rate is well understood, but there are other cost recovery issues whose importance is less well appreciated. Three of these are discussed below: transfer pricing; ring-fencing; and the treatment of abandonment costs

Transfer pricing involves investor allocation of revenues and costs across countries or even across fiscal boundaries within the host country with the specific purpose of lowering income subject to tax or sharing. Inattention to potential transfer pricing abuse can be hugely costly in terms of government lost revenues. Investors may seek to lower revenues, and so taxable income, by selling to affiliates at below market price. They may artificially inflate cost deductions, and so again lower taxable income, by excessive use of debt finance at above market interest rates (almost all fiscal regimes allow interest as a deductible cost), by charging excessive management and headquarters fees, and/or by above market cost provision of consultancy fees or goods from affiliates. Host government can and should protect themselves against transfer pricing abuse by taking a number of steps, notably by introducing legislation or regulations providing for: adjustments to ensure arms-length pricing; adoption of OECD guidelines on transfer pricing; mandatory disclosure of related party transactions; and investor documentation on the determination of transfer prices.

Ring-fencing relates to the tax treatment of costs from more than one project within a license area. Ring-fencing requires that costs be separated for tax or cost recovery purposes, i.e., costs from one project cannot be consolidated with income from another project. This has several advantages. Perhaps most importantly, it avoids the deferral of tax payments that would result if consolidation were permitted. It also avoids administrative complexity where multiple tax regimes exist within the host country. Finally, it levels the playing field for newcomers who will not be disadvantaged compared to investors with established income-producing operations. While ring-fencing is an increasingly popular feature of petroleum fiscal regimes, some countries still chose to allow consolidation of projects for tax purposes. This typically happens where the host country is anxious to see exploration and development move quickly. Consolidation would encourage this, albeit at the cost of deferred government revenues.

Legislative requirements for environmentally sound clean-up and site restoration operations at the end of an oil field's producing life have become almost universal. By definition, however, there is then no income available for the recovery of such abandonment costs. Since the costs are liable to prove considerable, investors will want to see up-front what provisions have been made to allow recovery of abandonment costs. Evolving practice has come up with two solutions. The first would allow current payments for approved anticipated costs to be placed in an escrow account to be drawn down on field abandonment. The payments would be deductible thus providing for cost recovery. The second solution also allows for current deduction of anticipated future abandonment costs, but instead of making payments into an escrow account, the investor must provide the host government with credible security that future abandonment costs will be met.

Withholding taxes and Double Taxation Treaties. Withholding taxes apply to income generated in the host country but paid to non-residents. The taxes are expressed as a simple percentage of the payment made and are in lieu of an actual income tax assessment which might be difficult to achieve due to the non-resident status of the tax-payer. Withholding taxes may be levied on payments to subcontractors, foreign loan interest payments and/or the remittance abroad of dividends. Withholding taxes are often reduced, sometimes significantly, under the terms of host country Double Taxation Agreements (DTAs) with countries where recipients of the dividends reside. This is important as withholding taxes are generally seen by petroleum investors as part of the overall tax burden on their operations. If the withholding tax is reduced at some point through a DTA, consideration should be given to making offsetting adjustments to other fiscal terms. At a minimum this calls for close communication between those responsible for the petroleum fiscal regime and those negotiating DTAs.

Taxes on transfers of interests. Transfers or sales of license interests can encourage efficient development by placing operations into the hands of those best qualified to finance and conduct them. However, gains realized by the seller in times of high petroleum prices may be very large and are often perceived negatively by host country authorities and/or public. Under such circumstances provisions for taxing those gains become important.

Several types of transfer exist. Where there is a direct transfer for cash the purchaser replaces the seller in the license to the extent f the interest transferred. Where the transfer of interest takes place offshore, the purchaser buys shares in the offshore company that owns the license interest in the host country. Unless purchase of 100 percent of the shares is involved this will not result in the buyer being listed as a license holder. A third type of transfer takes place when the buyer acquires an interest in the license through disproportionate
spending or work in the license area on behalf of the seller. The tax implications for each type of transfer are different.

Several options exist. One is to not tax the transfer. This is the case in Norway where the government values the potential efficiency gains through allowing interest transfers more highly than possible revenue gains obtainable by taxing them. A second option is to tax the seller on the gain but at the same time allow the purchaser to deduct the purchase price for tax purposes. This type of symmetrical treatment, practiced in Angola, has the same results as no taxation, except that tax revenues are accelerated since the capital gains tax is received at time of transaction, but the offsetting tax deduction is deferred through depreciation. A third option is to tax the seller but disallow deduction of the purchase price by the seller. This acts as a significant disincentive to efficient transfers. Uganda has adopted this approach.

While taxing direct transfers, government may decide not to tax offshore share transactions in recognition of the likely legal challenges and difficulties of detection and assessment of the gain. Alternatively, it may decide to deem gains on offshore transactions as earned by the local entity and tax accordingly. This option is under consideration in several countries but has yet to be implemented.

Where the transfer is made through a farmout, government might consider the disproportionate spending as a taxable gain, but this has never been practiced.

As to the tax rate to be applied, it should be noted that capital gains are frequently taxed at below the general corporate income tax rate in recognition of: (1) the likely impact of inflation on the taxable gain, causing the nominal gain to appear much greater than the real gain; and (2) the perceived benefits of transfers.

Compliance with capital gains taxation has sometimes proved a problem. A number of countries have addressed this by conditioning government approval of the transfer (a standard provision in petroleum laws and contracts) on payment of the tax by the seller.

Fiscal stablisation. Contractual provisions stabilizing agreed fiscal terms are justified in the investors' eyes by the large upfront investments, long payback periods and political risks associated with petroleum exploration and development (see Section II above).

Stabilizing provisions are of two types. The "frozen law" approach fixes the investment framework in place at the time of contract or license award for X years. The compensatory approach calls for any changes adversely affecting the investor to be offset by new incentives.

A number of issues arise. The original framework may have provided for investor benefits that are clearly no longer sustainable. After a number of years, it may be hard to determine or agree what the original framework comprised. If the compensatory approach applies, it is likely to prove very difficult to agree appropriate offsets. Where stabilization is accepted, should it apply only where the investor is adversely impacted? Should this asymmetry be corrected to rule out benefits to the investor when changes are favourable?

Some countries provide for stabilization as an option, with a price. For example, if an investor insists on having it, the applicable royalty will be X percentage points higher. Peru's mining investment framework offers this option. Other countries, recognizing the arguments for stabilization, but also the strain that changed circumstances can place on an agreement, provide for periodic reviews of terms with the investor. A robust fiscal regime that produces a reasonable sharing of risks and the economic rents and adjusts automatically to changed circumstances will increase the probability of fiscal stability, with or without an actual stabilization provision, and reduce the pressure to renegotiate agreements. The ROR approach to rent capture discussed in Section IV of this chapter is a good example of such a regime.

Recent dramatic cycles in the petroleum industry have increased the focus on stability clauses. Emerging good practice makes a number of recommendations for situations where stability provisions are adopted. Assurances of stability should be time-limited. They should also be limited in terms of coverage, e.g., cover only such items as capital recovery rules, income and withholding tax rates, royalty rates, and a maximum rate on import duties. They should not include changes in tax law that affect businesses generally, i.e., that do not discriminate against petroleum. Changes in environmental or health and safety regulations are examples.

VIII. Summary and conclusions

Fiscal regimes are of central concern to host governments and investors alike in petroleum prospective or producing countries.

The petroleum industry has a number of special features that need to be considered when putting in place a fiscal regime. These include, non-exclusively, the considerable investments required, typically long pay-back periods and significant political risks.

The initial design of a fiscal regime or any major revisions should be conducted against an agreed list of objectives for the regime. From the host country's perspective important objectives include: the promotion of efficient production and of broad-scaled sector development; substantial and progressive capture of petroleum rents for the state; incentives to cost containment; early and dependable revenue; reasonable management of risks; international competitiveness; and ease of administration. Government and investor objectives are not always aligned but a well-designed regime can go a long way towards balancing their interests.

Multiple fiscal objectives require multiple instruments. Profits-based instruments are effective in promoting efficiency and broad-based development, but they have perceived drawbacks under the headings of timing of revenues and ease of administration. Royalties provide early revenue and are perceived as easy to administer (although this is subject to challenge). However, they are inefficient and their impact is regressive rather than progressive. Flexible rent capture mechanisms are now widely found, but they vary greatly in effectiveness. Regimes which link government take to an investor's actually achieved rate of return are increasingly adopted and look the most promising. State participation in petroleum operations is common. In most cases it has fiscal connotations that need to be recognized.

No country relies exclusively on one fiscal instrument. Fiscal packages are the norm. The two most popular are the tax/royalty and production sharing regimes. Either of these may include some form of state participation. It is not the package label that counts however. Tax/royalty and production sharing can be designed to produce equivalent fiscal results. It is the detailed content of the package and the particular parameter values chosen that will be determine whether it performs well or not against fiscal objectives.

Petroleum prospective or producing countries are strongly advised to acquire through consultancies or develop internally the institutional capacity to evaluate fiscal regimes. This capacity will prove valuable in a number of areas; initial regime design; license rounds and negotiations; audit cross-checks; sector and macroeconomic planning. Inter-agency cooperation and timely access to credible data and are essential to success.

In practice the business of designing and maintaining a petroleum fiscal regime is complex. The sections above give a broad-brush idea of what is involved. The immediately preceding section, Section VII is meant to give a highly selective taste of complexities arising at a more detailed level of examination: fiscal price determination; cost recovery issues (transfer pricing, ring-fencing, treatment of abandonment costs); withholding taxes and double taxation treaties; taxes on transfers of interests; and fiscal stabilization.