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Host Country Agreements: Types and Trends by Region, Legal Issues, Pitfalls and Best Practices

Part 1: Introduction and Regional Trends

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Part 1: Introduction and Regional Trends

Introduction to Host Country Agreements

Outside parts of North America, the ownership of natural resources such as petroleum (here meaning crude oil, natural gas, and similar substances naturally occurring in the subsurface) is vested in the State. Most, but not all, States encourage the exploration, development and production of petroleum resources, not by state-owned entities, but by other domestic or foreign entities for profit. Resource development by a non-state entity requires a commercial and legal framework. Apart from regulating the industry, this framework must include the mechanism(s) whereby the State extracts an economic rent to compensate for the use and depletion of its natural resources.

The required framework includes (i) an overarching petroleum or natural resources law sometimes accompanied by detailed regulations, (ii) fiscal laws, whether the tax laws generally applicable to corporations or individuals, or special petroleum tax laws, and (iii) an instrument granting the right to explore for, develop and produce petroleum (a Host Government Instrument or HGI). This right to develop and produce petroleum (i) relates to a fixed land or maritime area, usually but not always some subdivision of the total area under the State's jurisdiction, and (ii) is granted exclusively to either an individual entity or jointly to an organized group of entities (although some types of exploration rights may not be exclusive, but generally these exclude the right to drill wells). A few jurisdictions have managed without an overarching petroleum law, generally enacting individual HGIs as laws in their own right.

For a variety of historical and political reasons, different types of frameworks have evolved within this overall structure. At one end of the spectrum, an HGI may consist of a simple license identifying the right-holder and the surface area to which it relates, stating that the licence is subject to the applicable laws and regulations, including the applicable fiscal terms. Typically many such identical licenses (over different areas, of course) are in force at any time. At the other end of the spectrum, the HGI may be a contract setting out all the necessary administrative, legal, operational and fiscal terms. These terms may be unique to the particular contract, and the contract may even be enacted as a law of the State in its own right even where an overarching law exists. In some systems, the right to develop and produce petroleum may be retained by the State through its national oil company (NOC) or regulatory agency. The third party is solely a contractor entitled to some contractually-defined share of the production.

A special case of the latter situation arises in a few countries which are reluctant to allow non-state entities, and in particular foreign entities, to extract petroleum for profit, but nevertheless wish to access both capital and technology from overseas. Contracts to allow this are called Service Contracts. Under a "pure" service contract, the International Oil Company (IOC) performs as a contractor for a fixed fee which includes a profit component. However, in practice some component of the remuneration, whether the reimbursement of costs or the profit component, is "at risk" because the timing and size of the payments depend upon the level of production achieved or the oil price or the profitability of the project. Such contracts are called therefore called Risk Service Contracts and are relatively uncommon. There are, however, well-known because they tend be used in countries where petroleum extraction is the dominant industry and is both economically and politically important (Iran, Iraq, and Mexico before the recent changes, for examples).

Across the spectrum of HGIs, it is tempting but difficult to "pigeon-hole" the arrangements into different categories. But it seems that for every generalization, there are exceptions. From a commercial perspective, arguably the most important consideration is how the State extracts economic rent, or put differently, how the value of the production is shared between owner (the State) and the party at risk, the developer. We therefore start by looking at the different mechanisms for sharing that wealth.

Resource Rent

Taxation is an important source of State revenue in most countries. Industrial enterprises are usually taxed regardless of whether or not they consume the State's natural resources. I will therefore introduce the concept of "resource rent" to include all forms of revenue and profit sharing accruing to the State **except** taxes that are levied on all industrial enterprises. One can distinguish between three resource rent extraction mechanisms:

(1) Royalties, including severance, ad valorem and similar taxes. These are levies on the value of the production (sales proceeds) without regard to the investments required for its (their) production, or whether the enterprise is profitable. Royalties may be a fixed or variable proportion of the sales revenue, or more rarely, a fixed monetary amount per unit of production. If variable, the royalty rate may increase with increasing production volumes, or sometimes price or even profitability. Some countries allow transportation, processing and/or a proportion of field operating costs and certain capital investments, to be deducted in arriving at the value for royalty purposes (often called the "wellhead" value).

(2) Taxes. Given the exclusion, here, of "standard" corporate taxes, this includes (i) the additional amount of corporate income tax due to the difference between the standard rate and the special rate for petroleum production, and (iii) special taxes assessed only on petroleum production activities, in addition to corporate income tax. In both cases they are based on profits (sales proceeds less allowable costs) rather than sales proceeds.

(3) Disproportionate sharing of production in favor of the state or its agent before the application of taxes, if any, on the contractor's profits. Usually called simply production sharing, I emphasize the word "disproportionate", which in this context means disproportionate to the respective shares of costs. Consider a joint venture between an NOC, holding a 51% interest, and an IOC, holding 49%, in

which both pay their respective shares of all costs and receive their respective shares of all revenues. This allocates a larger production share to the NOC, but is not "production sharing" in the usual industry sense, because it is not disproportionate. If the NOC pays its 49% share of costs, but receives a larger share of the production, say 60%, then that is production sharing. Such high levels of State cost-sharing are relatively uncommon, and I will return to the issue of state participation as a separate topic later.

Note that the special case of Risk Service Contracts does not, at first glance, appear to fit into any of these categories. However, a relatively small fixed fee payment to a contractor is similar in effect to a very large fixed royalty per unit of production (where the effective royalty per barrel is the sales price less the contractor's fee). Perhaps more appropriately, since Risk Service Contracts frequently have the equivalent of "cost petroleum", it is like a production sharing contract with a complex profit sharing formula that leads to a fixed fee per barrel. I say this because from a commercial perspective, Risk Service Contracts are only special in the need to retain politically or constitutionally correct language for public consumption. The oft-quoted issue that IOC's are unable to "book" reserves under a typical Risk Service Contract seems to me to be a poor basis for regarding them as special from a legal or commercial perspective.

Some additional comments on resource rent may be useful. Petroleum extraction requires considerable capital and there are continuing operating costs and ultimately abandonment costs. Resource rent should be thought of in terms of the division of profits. As noted above, in simple terms, taxes are levied on profits. Most, but not all, production sharing systems set aside a portion of production to reimburse costs ("cost petroleum"), and the disproportionate production sharing is only applied to the profits ("profit petroleum") and might be better described as profit sharing. Royalties, however, take very little or no account of the costs of development. Royalties are generally relatively small fractions of sales revenues, but are a larger fraction of profits. Good "government take" statistics take into account the effect of the royalty as a fraction of profits, even though levied on sales revenues.

Global Practice

All three resource rent extraction mechanisms, Royalties, Taxes and Production Sharing, can, and do, co-exist in any particular fiscal system. To illustrate this I use a ternary diagram, widely used in geology to illustrate the proportions of each component in a three component mixture. In a ternary diagram each vertex of the triangle represents the point at which one component is the sole component. As the other two components are introduced, the mixture is plotted further away from that vertex, until, when the mixture contains none of that component, and is made up solely of the other two components, it is plotted along the base line opposite its vertex. A mixture of equal parts of all three components plots at the centre of the triangle. Figure 1 is a ternary diagram illustrating the relative proportions of Royalties, Taxes and Production Sharing that make up the government take in a large number of fiscal regimes. Note, importantly, that this shows the relative proportions of each component. It does not indicate the overall size of the government take; that is illustrated by the size of the circle on the plot.

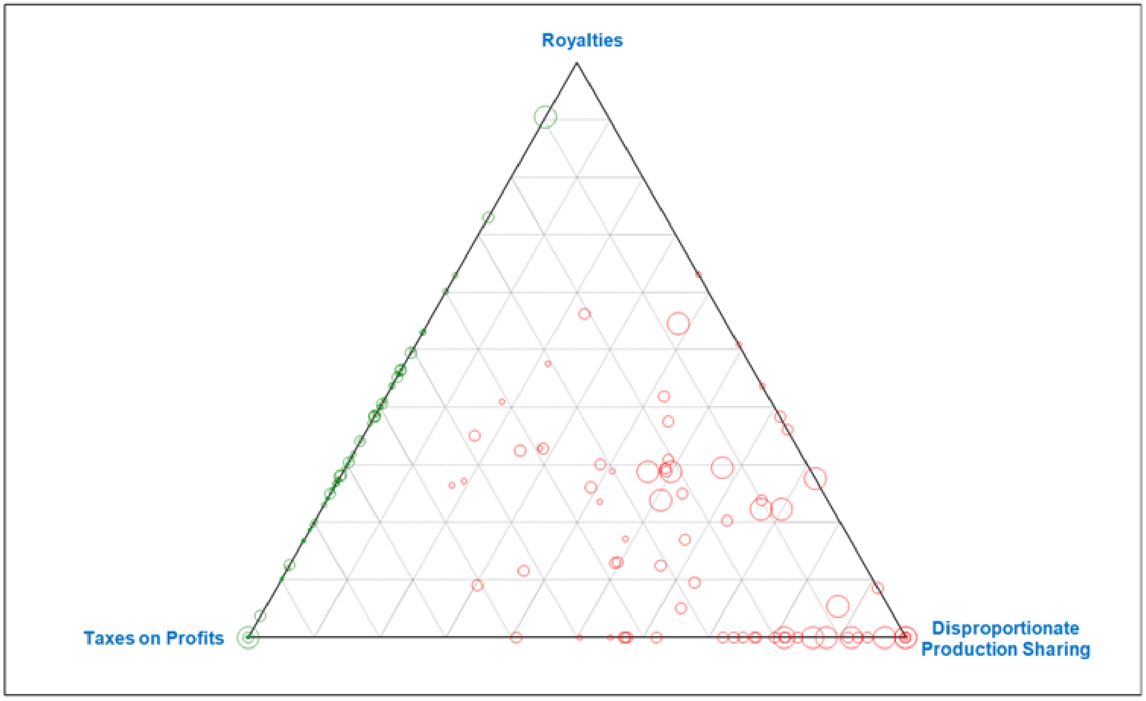

Figure 1: Ternary Diagram showing the relative proportions of government take separated into Royalties, Taxes and Production Sharing. Circle sizes show relative size of government take, largest circles being largest takes.

Some caveats are necessary. The plot was constructed in 2004 by one of our analysts, and was not intended to be exhaustive. It was based on representative arrangements in place over the preceding decade or so. Taxes here include all taxes, with no distinction between "ordinary" corporate taxes and additional taxes capturing resource rent. For almost all systems, the relative proportions are sensitive to price, and the plot was made using a somewhat outdated $20 oil price. The plot appeared to have limited value other than as a curiosity, and has not, therefore, been updated.

On Figure 1, green circles represent systems with no component of production sharing, and all plot along the Royalty/Tax baseline. We call these, rather obviously, Royalty/Tax (hereafter "RT") systems. The red circles represent all systems that have some element of disproportionate production sharing. These are called, again rather obviously, Production Sharing (hereafter "PSC") systems. It can be argued that the vast majority of systems use all three components, and perhaps anything not at a vertex could be called a hybrid. Note, however that there is a gap between the envelope of all PSC systems, and the Royalty/Tax baseline. Generally, if a fiscal system includes production sharing provisions, that component is a material part of the State's overall take.

Note that more of the largest sized circles are colored red rather than green. This has led some to state that PSC systems are more onerous than RT systems. This need not be true.

From an IOC's perspective there are benign PSC systems and punitive RT systems. It may be shown that any PSC system can be replicated by an RT system. However, this may require complicated petroleum tax formulae.

There is elegance to the production sharing mechanism alone as a means to capture resource rent. It is therefore perhaps surprising that many systems incorporate production sharing but also include significant elements of royalty and taxes. This observation deserves further comment.

The production sharing mechanism as originally conceived unfortunately fell foul of the administrative realities for U.S companies and, more recently, U.K. companies. Since these countries are home to both most of the "super-majors" and many of the smaller independent IOCs, these firms' issues have to be addressed. Production sharing as a resource rent mechanism theoretically replaces the need to tax, as the tax component is subsumed to the overall resource rent taken in by the production sharing mechanism. For companies taxed on their global income (as in the U.S. and U.K.), with only actual foreign taxes paid creditable against a domestic tax liability on foreign income, a foreign tax element hidden (not explicitly determined and paid) in the production sharing mechanism creates a significant issue. Without explicit foreign taxes paid, these companies face a residual domestic tax liability that effectively transfers resource rent from the host government to the country of the IOC's domicile. This anomaly was recognized early, and almost all PSCs now include a determination of a host country tax payable that reduces or eliminates the transfer of resource rent to a foreign treasury. The tax may be paid by the IOC, or paid out of the State's disproportionate production share ("tax paid" systems). The result is the same for the IOC, but may have different results with regard to whether and how the fiscal terms are stabilized, an issue that will be discussed later. For present purposes, the tax element of a production sharing mechanism is included in the statistics as a tax. But theoretically it is not required, and its inclusion distorts the component of "taxes" in a discussion of the relative importance of the different components of resource rent extraction. Note, importantly, that a pre-tax production sharing mechanism accompanied by a tax on "profit petroleum" is precisely equivalent to a post-tax production sharing mechanism with no tax, but with appropriately reduced contractor shares.

Many production sharing systems retain the royalty concept. As with taxes, this is theoretically unnecessary but unlike taxes, its retention is not required to satisfy any particular issue. Royalties guarantee a share of production for the State (whether taken in cash or kind) from the moment production starts. But in PSCs there is, or can be, another mechanism to ensure a guaranteed flow of revenues to the State. Many PSCs cap the amount of production available for the reimbursement of costs (usually referred to as a "cost petroleum" cap or ceiling). This means there is always an element of "profit petroleum" in which the State shares. This appears to make the concept of a royalty redundant in a PSC system, but it is nevertheless common. The allocation of revenues between the NOC, the State treasury and provincial or local authorities may depend on whether the revenue is from royalties, taxes or production sharing. This may provide a practical explanation for retaining the distinctions in a PSC system.

Categorizing Fiscal Systems

Several other generalizations about the differences between RT and PSC systems are made. Some are usually, but not always, true, and some may be usually true but are not, to my mind, particularly useful.

One pigeon-holing attempt suggests one should distinguish between contractual systems and non-contractual systems. The distinction would be somewhere along the spectrum described earlier, between the simple license with no individual contractual "meat" and the detailed and possibly unique, comprehensive contract. The suggestion is that PSC systems are, together with Risk Service Contracts, contractual, and RT systems are not. This might be a useful distinction, but there are RT jurisdictions where the HGI looks exactly like a PSC in all respects other than the allocation of production.

Another common issue used to distinguish between RT and PSC systems is that ownership of petroleum passes to the IOC at the wellhead in an RT system, but at some point further downstream, typically an export terminal, under a PSC. While this may be common, it has always struck me as more of a curiosity that anything meaningful. In deep water production systems in West Africa, for example, does this really matter when the wellhead and offshore loading flange are no further apart than opposite ends of the same boat?

A perhaps more interesting ownership issue relates to the wells, facilities and pipelines built to produce the resource. Under PSC systems, ownership often passes to the State rather than being retained by the IOC. Timing varies. In some systems it passes on arrival in the country or installation. In others it passes once the contractor has been reimbursed for the cost. In others it passes at the end of the contract. For the life of the contract, the IOC is indifferent to this arrangement because it is allowed to continue to use the assets. However, it provides leverage to the State on expiry of the contract, as the possibility exists to take over operations, or indeed contract with another IOC, rather than negotiate with the existing contractor to extend the contract. On the other hand, this might relieve the IOC of the responsibility for abandonment costs, although most contracts provide for these to remain the responsibility of the IOC.

It has been argued that the PSC structure allows the State or its NOC more control over the management of operations. This argument does not refer to the effect of State participation, as that is not excluded from RT systems although it is rare. It refers to the extensive State or NOC role in managing the operations as contractual counterparty in a PSC. However, contractual or regulatory procedures can be put in place under an RT system to give the State, usually through its regulatory arm, a similar level of oversight and participation in major decisions.

Most systems have some flexibility in providing different terms for different categories of activities that may require incentives to be commercially attractive – natural gas, heavy oil, unconventional resources, etc. However, one important difference between typical RT and PSC systems is the coexistence, in PSC regimes, of contemporary contracts for similar areas with different fiscal terms. Typically, in RT systems, contemporary contracts for similar projects have identical fiscal terms, but under PSC systems they may vary either as a result of direct negotiation or competitive bidding. Because different tax rates are either administratively complex or legally impractical, competitive bidding under RT systems is usually limited to signature (or other) bonuses, work programs, and perhaps commitments to use local goods and services. Since HGI-specific royalties may be incorporated into individual RT HGIs, the ability to incorporate competitively bid royalties exists. In practice, this does not usually occur, with Mexico being a significant exception. But for PSC systems, the production sharing arrangements are potentially unique to each contract, and this lends itself to having competitively bid fiscal terms. There are advantages and disadvantages.

Competitively bid fiscal terms allow the market to determine the appropriate level of resource rent. Terms may be less onerous in less prospective acreage to encourage investment there. For highly prospective acreage, competitive bids maximize potential resource rents, at least in theory.

Two observations suggest that the results may not be optimal. First, there may be different fiscal terms for different areas, negotiated before exploration success was achieved (if indeed it was). Following success, the different terms yield different government takes for developments in possibly adjacent areas. Having now forgotten the contractor's previous exposure to the risk of failure, there is a temptation on the part of the State to want to change those terms to equalize the State take in all developments. Second, competitive bidding results in the winner being (other things equal) the firm with the most optimistic outlook about success ("winner's curse"). In a competitive bid under the extreme uncertainties involved in forecasting outcomes from petroleum exploration, it is likely that the winner will have overestimated the true value of success. While the host government may be satisfied with the winning bid terms, there is a substantial risk that a less optimistic outcome will occur, leading to the need to renegotiate the terms to allow development to proceed.

Best Practice and Global Issues

From the combined perspective of both the host government and the investor (the IOC), one can perhaps state that best practice results in:

(1) Maximizing timely and efficient direct investment in the petroleum sector, if indeed that is a host government goal (it is not in all countries), and

(2) Maximizing the host government's resource rent without diminishing the level of direct investment.

I would add the following two cardinal rules for fiscal regimes:

(3) Incremental production (sales revenues) should result in incremental revenue to the IOC.

(4) The IOC should be incentivized to reduce costs.

All of this requires a balance. From the preceding discussion, I hope it is apparent that these objectives can be achieved independent of the type of resource rent extraction method and contractual structure employed. Achieving these objectives is much more a function of the particular detailed terms under which any particular system works. Unfortunately, my suggested rules for best practice are not always followed regardless of the type of system employed.

The following discussion of regional trends discusses the types of systems employed, but also reviews trends in terms of specific issues that are important beyond that choice. I will address the stability of those systems, both in terms of contractual stabilization and the likelihood of systems surviving significant changes in the fundamentals of the industry, product prices and costs. I will address the role of State participation. I will defer to others a discussion of dispute resolution, although this remains an important issue when arrangements break down in the presence of significant changes in the fundamentals.

Regional Trends

The presentation of regional trends in a concise and sensible form presents a number of problems. How does one illustrate the wide variety of individual contracts, when I have noted that the PSC systems frequently allow for different fiscal terms to be applied for individual PSCs? Perhaps more importantly, should one give added weight to those systems which (i) result in large numbers of individual contracts, or (ii) are the most important because they are representative of the most important producing countries? Alternatively, one could provide global maps with the jurisdictions shown according to their usage. I find this unsatisfactory because it gives too much weight to large countries (by geographic area) and little weight to countries small in area but with relatively significant petroleum industries. As a compromise, the charts (maps) shown here are diagrammatic, with each jurisdiction given a square of equal area.

“Jurisdiction” requires a definition. For present purposes, this includes areas governed by treaty that are not sovereign states, such as the joint development zones (Malaysia/Thailand, Timor-Leste/Australia, Sao Tome/Nigeria, etc.). Countries where resource management is devolved to (or was always reserved by) states or provinces in a federal system create another issue, complicated by the fact that the maritime Exclusive Economic Zone may be administered by the federal government (Australia, USA). I have made arbitrary choices with respect such situations, frequently grouping federal subdivisions if their systems are similar in overall impact. Some jurisdictions allow alternative systems for different locations (typically, onshore versus offshore, as in Netherlands and Pakistan, for example). For those, the alternatives are shown by dividing the jurisdiction’s single square. For those jurisdictions whose laws allow for alternative regimes, I have generally chosen to represent them on the basis of the system recently in common use.

Fiscal practice is dynamic. The accompanying charts are based on current or recent practice, as best as I have been able to determine. This may not reflect the predominant historical practice. Thus, for example, Algeria is shown as an RT system with a majority state participation, although current production, and quite probably most future production in the short term, is and will be from PSCs, usually with smaller State participation.

Note that the terms referred to usually relate to crude oil. Natural gas terms add to the complexity. Natural gas is not fungible, at least from a global perspective. Particularly where a market for natural gas is yet to be developed, terms for natural gas may be very different from those for crude oil, even where the overarching petroleum law makes no distinction between oil and gas. Special treatment for natural gas can include royalty relief, fixed rather than variable production sharing, and the absence of price-based additional profits taxes.

Keeping up with all the changes to fiscal terms is a challenge. Any errors or omissions in the analysis shown here are entirely mine.

Regional Trends: Resource Rent Extraction Methods

Figure 2 shows the nature of the resource rent extraction methods employed around the world. I have returned to the concept of resource rent discussed earlier. "Standard" corporate taxes are excluded, so that where either taxes or royalties and taxes are shown as generating resource rent, this means there is either a special tax on petroleum, or corporate income tax is assessed at a higher rate for petroleum than on other industries generally.

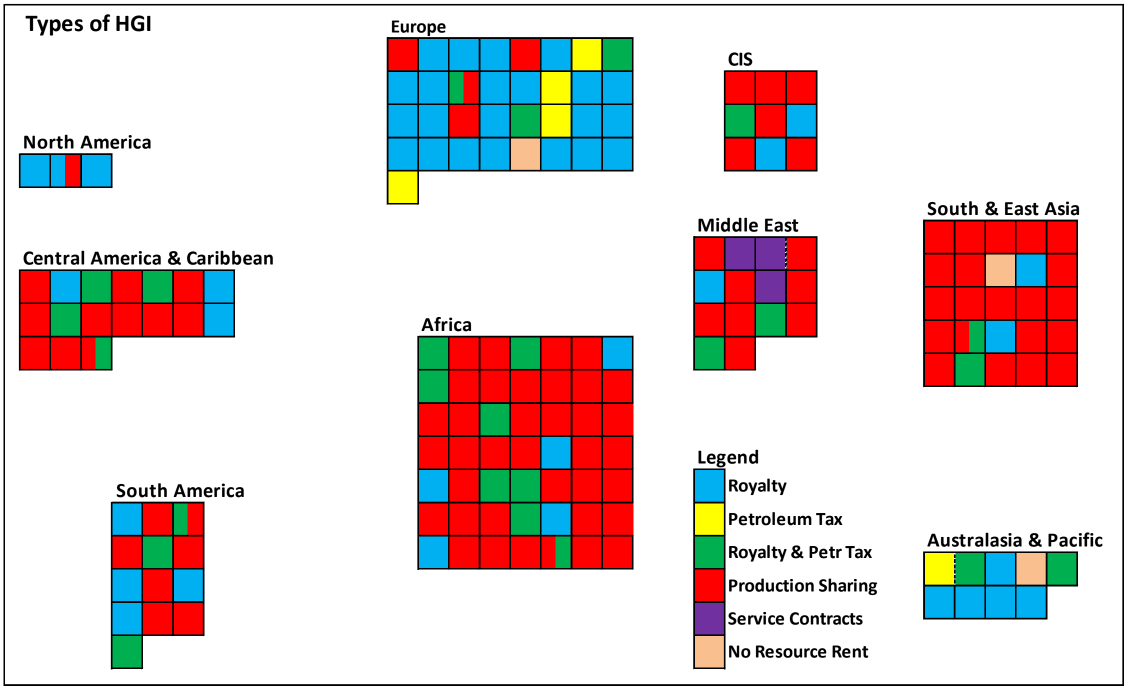

Figure 2: Global Schematic showing Resource Rent extraction methods by jurisdiction by region.

Very few jurisdictions extract no resource rent, generally those with limited or, as yet, no resources. Standard corporate tax rates apply, so activities do (or it is hoped will) generate revenue for the State. Omitted for clarity are those jurisdictions that have yet to enact legislation governing petroleum extraction, perhaps because their territories are thought to be non-prospective. Also omitted is a very small number that have exploration activity, but the HGI details are not available to me.

Based on numbers of jurisdictions, RT systems dominate North America (83%), Australasia & Pacific (89%) and Europe (86%). Relatively sophisticated systems including some form of industry-specific tax are found in the North Sea/North Atlantic and Australia, but otherwise most countries rely solely on relatively modest royalties.

PSC systems are dominant in South and East Asia (82%), Africa (74%) and CIS (67%). They are also important in Central America (62%), Middle East (57%) and South America (50%). With exceptions, RT systems in all these regions include industry-specific taxes of varying degrees of sophistication.

Stability

Petroleum development is a long term, relatively high risk, capital intensive enterprise, in which initial revenues, let alone repayment of the capital invested, may not occur for many years. In order to make large long term capital investments, investors (IOCs) require assurance that the fiscal terms under which they agreed to make these investments will survive over the term of their contract. The situation is made even more complicated by two particular problems with respect to investments in petroleum projects.

First, exploration investments are made under the assumption that there is a high likelihood (more than 50%, and frequently 70%-90%) that the investment will fail and generate no future income, with no tax offset in the country of investment to mitigate the loss. To account for this, the value of success (the reward) must be large enough to justify the exposure to loss. This is usually recognized in the terms of the HGI. However, if successful, the risk of failure is removed, and the terms under which development moves forward may appear generous to the IOC. The host government, possibly under popular pressure, may wish to "re-balance" the terms on the State's favor.

Second, product prices have become increasingly volatile, but with an asymmetric response. Increases in prices lead to popular demands for "windfall" taxes, but reductions in prices meet with no sympathy (although governments will respond to systemic price falls with improved terms, these usually relate to future rather than existing contracts).

Stability is therefore of considerable importance to IOCs, particularly in States with a volatile history with respect to the treatment of foreign investments. Stability can be accomplished in one of two ways, although the two mechanisms are usually not talked about together. First, one can introduce stabilization mechanisms into the fiscal system (contractual stabilization). Second, one can design fiscal systems that respond, preferably equally, to upward or downward movement in product prices (progressive fiscal systems).

Contractual Stabilization

Much has been written about the legal issues raised by stabilizing fiscal terms in an HGI. Significant legal issues are raised about the enforceability of stabilization clauses that purport to freeze laws, thereby possibly binding future governments and limiting sovereign States' rights to regulate and tax. I will ignore such legal issues. Nevertheless, I will contrast three different approaches, and then review their usage in different parts of the world.

Generally, host governments have been sympathetic to IOC demands for stabilization, because the basic need, for large amounts of foreign direct investment in the petroleum sector combined with industry knowledge, was paramount. Stabilization is therefore fairly common. Unfortunately this has resulted in "seller's remorse" in a number of jurisdictions over the last five years or so, following the oil price increases, industry successes beyond expectations, and political changes.

Systems with fixed terms (I avoid the term "freezing" because of the legal issues raised) provide that the fiscal system is fixed by the HGI, either with explicit rates or by reference to the terms in force at the time the HGI is enacted. Importantly, however, such terms are usually incorporated with regard to existing taxes (usually corporate income taxes) and this only stabilizes the overall fiscal regime if it is accompanied by an exemption from all other taxes (including new taxes in the future).

"Tax paid" systems are limited to PSC regimes. Here, recalling the original elegant PSC approach, taxes are subsumed to the overall resource rent taken by disproportionate production sharing. Taxes (and sometimes royalties) are paid out of the host government share of production and the IOC is immunized from changes in rates. Again, though, this only stabilizes the overall fiscal regime if it is accompanied by an exemption from all other taxes.

An increasingly popular approach is to include an "equilibrium" clause. This states that if circumstances change (usually laws and regulations, but occasionally any material change in circumstance) to the detriment of the contractor ("asymmetric" clauses) or either the contractor or the State ("symmetric" clauses), then the parties will renegotiate to restore the economic "equilibrium". I am personally very scathing of such arrangements as they are ambiguous. As an IOC, is my "equilibrium" position to be based on retaining my share of the net present value, or retaining my return on investment or similar profitability measure? Put more simply, if the pie gets bigger, am I entitled to the same fraction of the pie or just the same amount of pie?

Figure 3 shows the incidence of some form of stabilization mechanism worldwide. Note however that this is not as exhaustive as the earlier chart. In particular, specific model stabilization clauses in any particular jurisdiction may be left in, taken out or amended in any particular HGI, and it is inaccurate to assume all contemporaneous HGIs contain identical clauses.

A check mark on Figure 3 indicates the presence of some element of stabilization, including jurisdictions where the corporate income tax rate is specified in the HGI as well as "tax paid" jurisdictions. As noted earlier, neither of these provides true stabilization unless accompanied by other clauses granting exemptions from all other taxes.

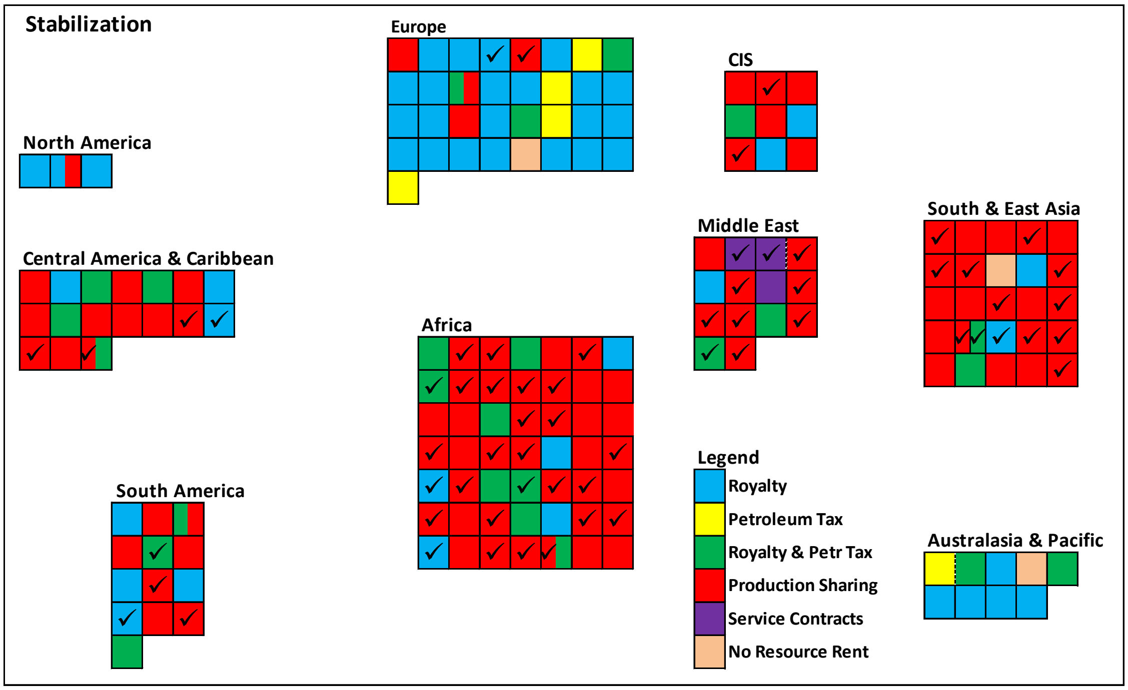

Figure 3: Global incidence of some element of fiscal stabilization (some element present if checked)

Stabilization is widespread in Africa, the Middle East and South & East Asia. It is less common in Central America & Caribbean, South America and CIS, and very rare or absent in North America, Europe, and Australasia & Pacific.

Progressivity

Terms that allow Host Government take (as a fraction of net profits) to increase with increasing profitability are more likely to survive unexpected changes in project profitability. Such terms include royalties, production sharing terms, taxes or special taxes whose rates increase with increases in profitability ("R Factors" or Rate of Return measures) or increases in sales price. R Factors are ratios of cumulative revenues to cumulative costs, although the details of the calculation may differ between jurisdictions.

Figure 4 shows the incidence of progressive elements of fiscal terms worldwide. This is qualitative. A progressive element does not guarantee that overall the system is progressive with respect to price (meaning, here, that host government take increases as a fraction of profits as oil prices increase)

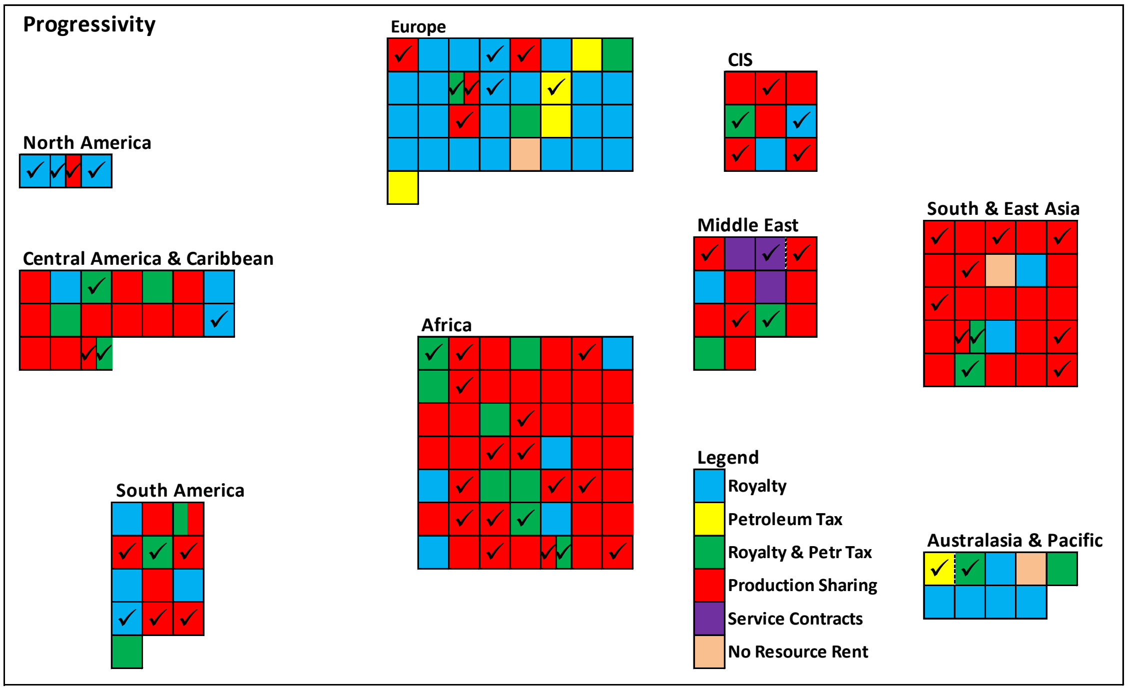

Figure 4: Global incidence of some element of fiscal progressivity (some element present if checked)

Only one third of the systems shown contain progressive elements. Outside North America, where price mechanisms are used to trigger or vary royalty rates, they are rare in pure royalty systems. The proportion rises to 39% of all systems if pure royalty systems are excluded, and is the same for PSCs (39%) and a little higher for systems with petroleum taxes (44%). The global distribution of progressive systems is therefore similar to the distribution of system types. One notable exception is Central America, where PSCs almost exclusively use production volumes for production sharing rather than progressive R Factors or ROR measures. This contrasts with Africa and South and East Asia, where PSCs with R Factors or ROR measures are more common.

State Participation

States are actively involved in upstream petroleum activities both in management (through the regulatory process and/or under the contractual framework of the HGI) and ownership of production (whether by taking royalties in kind or having a production entitlement under a PSC).

Many HGIs include an additional form of state involvement, frequently in PSC systems and less frequently in RT systems. The State, or more usually its NOC, may become a working interest holder in the HGI on essentially the same terms as the IOC. This is referred to, perhaps confusingly, as “State participation”. When one hears the expression “no State participation” with respect to HGI terms, it is this working interest participation that is referred to. An important difference from the IOC’s working interest is that the State participation may be “carried” through the exploration phase. This means the State does not pay its share of the at-risk exploration costs, but pays its share of development and operating costs in the event of a commercial discovery.

This distinction is important. The carried State share is a burden on the IOC and substantially affects the attractiveness of an exploration opportunity. Before considering risk aversion, an IOC must be provided with double the reward (the value of a successful outcome) to carry a 50% State participation entitlement in order for a project to meet the same economic criteria compared to one where there is no State participation. Risk aversion exacerbates the problem, as the IOC's valuation is dominated by the expected cost of failure (the cost of failure times the likelihood of failure). The reward must therefore be set even higher to compensate for the increased cost of failure. The required reward may be so high that it aggravates the previously stated problem where, given success, the contractor's risk is forgotten and its reward seems too high.

In the success case, however, the IOC is indifferent to the addition of a paying partner provided it can pay its cash calls in a timely fashion. It is no different to having another IOC partner. The State may reimburse the "carry" or else the IOC receives the tax deduction or cost recovery for the costs it carried on the State's behalf.

From a host country perspective, there are advantages and disadvantages to participating in a development. Much has been made of the "information asymmetry" between the sophisticated IOC and the supposedly naïve NOC or State. Participation by the NOC on the same side of the table as the IOC reduces that imbalance. It also provides a mechanism for knowledge transfer, necessary to develop NOC competence. But there are disadvantages. Participation of the NOC as part of the contractor group is an inefficient way to participate in the revenue generated by the project, as its share of the project generally suffers the same resource rent extraction burdens as the other members of the contractor group. It also requires substantial investments by the State, in competition with other State responsibilities and social burdens.

Nevertheless, State participation is a global phenomenon. Figure 5 shows the incidence of State participation worldwide. In many cases, the level of state participation is a negotiable or biddable element. Moreover, it is usually an option to participate, generally exercisable upon the declaration of a commercial discovery, or the approval of a development plan.

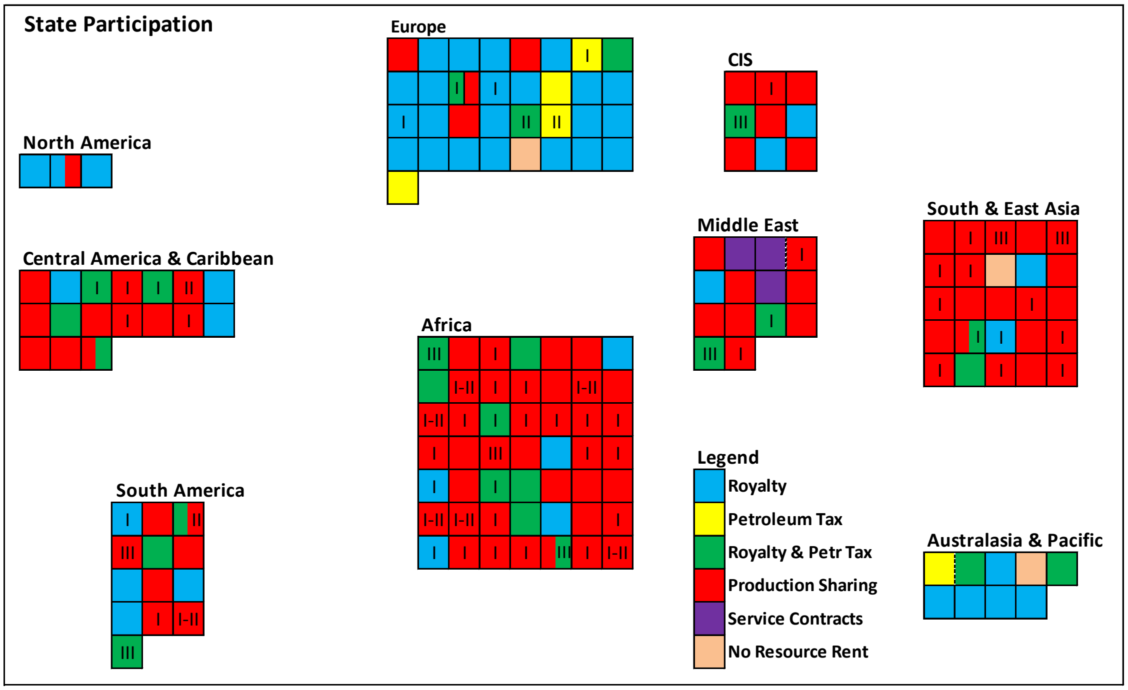

Figure 5: Global incidence of state participation (roman numerals indicate level of participation; I: Up to 25%; II: Over 25% but less than 50%; III: 50% or more). No distinction is made between "carried" interests and paying interests.

Overall, the state participates in 38% of the jurisdictions shown. It is most common in Africa (60%), South and East Asia (50%), and South America (46%), but less so in Central America (35%). In parts of Africa and Asia it has enabled start-up NOCs to develop into fully functional companies, some of which have started to seek projects beyond their own borders. In other parts of the world NOCs have existed for many years, and continuing State participation is seen as a political necessity (parts of the Middle East, South America and CIS) or simply a legacy of historical practice (other parts of the Middle East and South America, as well as parts of Europe).

Conclusions

There exists a broad spectrum of Host Government Agreements which can be categorized by general type but which defy precise pigeon-holing. Regional differences are apparent but these merely reflect historical practice and preferences. Best practices are not a function of types of systems, but rather the detailed individual application of whatever system is employed, and its local variations and choices. Stable fiscal systems can be achieved through different approaches, whether contractual stabilization mechanisms or putting in place a progressive system that is robust under changing circumstances. It is surprising that progressive systems have not been adopted more widely, as they have been advocated and used successfully in some jurisdictions since the 1970s. Other issues, such as State participation, have important consequences, but it is not clear that there is any optimum approach.