PRELIMINARY REPORT ON FISCAL DESIGNS FOR THE DEVELOPMENT OF ALASKA NATURAL GAS

BY
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For

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Section 2.2

What do upstream fiscal regimes around the world look like?

Part 2: Natural Gas Fiscal Design - Clarifications

2.2 What do upstream fiscal regimes around the world look like?

Generic Fiscal Designs

There are more varieties of upstream fiscal systems operating in the world than there are countries. Most upstream fiscal systems integrate a number of fiscal elements driven by different factors (e.g. production volume, profitability measurements, product prices, water depths etc.). Many countries operate more than one fiscal system for historical reasons and to address different petroleum provinces with different issues and at different levels of maturity. Moreover, upstream fiscal systems evolve with time and are constantly amended to respond to changing market (price) environments and reservoir/environmental challenges. The fiscal design process is therefore dynamic and ongoing and needs to anticipate industry and market trends in order to establish mechanisms that both promote investment and provide governments with adequate shares of economic rent. The fiscal design process needs to be dynamic, but once a design is adopted a government should resist the temptation of introducing frequent amendments and instead apply only occasional, prudent adjustments to respond to unforeseen circumstances or substantial changes to market conditions and/or exploration and production activity.

The types of upstream fiscal system in operation are classified in Figure 2.2.1.

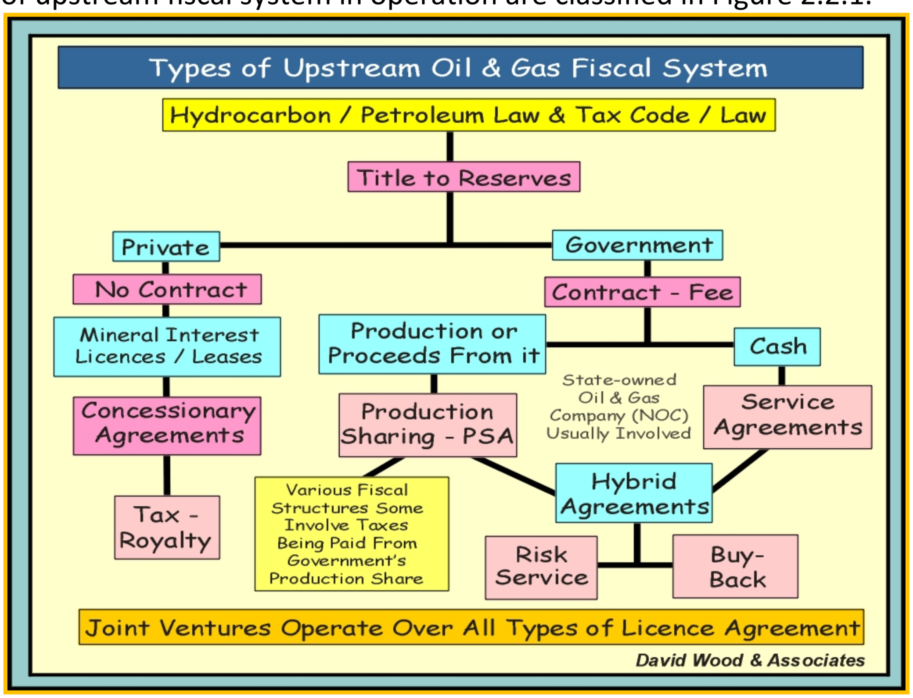


Figure 2.2.1 Generic types of upstream fiscal system: Mineral-interest and production-sharing systems predominate. Alaska (and all U.S.) fiscal systems belong to the mineral-interest group (column on the left).

Even though Alaska owns much of the land and subsurface mineral rights in the state, it has transferred -- through its mineral-interest leasing program (Figure 2.2.1) -- the right to the ownership of the oil and gas produced from those reserves to its lease holders.

From a sovereign perspective the key objectives of fiscal design in the upstream gas and oil sector are to:

1. Divide economic rent appropriately.
2. Ensure efficient and environmentally appropriate development of resources.
3. Promote investment of both development and risk capital.
4. Provide a mechanism for cost recovery that does not penalise commerciality (i.e. provide a producer with a reasonable return on any investments made in a realistic timeframe).
5. Create a flexible regime that responds effectively to changing market conditions and projects of varying size, cost and risk.
6. Establish transparent fiscal instruments that can be easily administered, audited and widely understood.
7. Promote competition among those willing to invest in exploration, field development and infrastructure construction. This may not be a universal objective, as in certain countries monopoly resource holders or infrastructure operators may be given preferential rights.

These objectives can be achieved from a sovereign perspective in a variety of fiscal designs, but two quite distinct generic designs have evolved that are widely employed in a variety of forms by countries around the world. These are:

Mineral-interest or concessionary systems
Production-sharing agreements (PSAs)

These two dominant systems are not the only ones in operation. Figure 2.2.1 summarizes these and other types of upstream fiscal agreements employed.

1. ***Mineral-interest or concessionary systems*** are also sometimes referred to as ***tax-and-royalty systems*** (not a good discriminator, as PSAs also often involve tax and royalty elements). These systems are operated through leases, licences and/or concessions administered by a government ministry or agency. They originated in the oil and gas sector in the United States and are maintained and favoured by most OECD governments, and many other developed countries where the governments usually hold mineral rights (U.S. excepted). The systems enable title to reserves discovered to be vested in the lease-holders, licensees, concessionaires, etc. through a license and/or permit system, usually with no other contract involved. Fiscal instruments applied to such systems include royalties, special petroleum taxes (levied on production or profits), property taxes (levied on onshore facilities) and corporate taxes levied on income. The rates of royalties and taxes are frequently linked to other metrics that trigger specific rates and increase flexibility. Bid bonus payments to secure leases through competitive

tender also constitute an important component of the income accruing to governments under such systems. Indeed on a discounted basis the U.S. government has extracted more value in recent decades from bid bonus payments than from royalty payments.

2. ***Production-sharing agreements (PSAs)*** involve contractual arrangements between sovereign states and participating companies (primarily international oil companies, IOCs) that are remunerated by shares of production that may also be additionally adjusted by tax, royalty and other fiscal instruments. PSAs are commonly negotiated and ratified by a government ministry or agency, but often administered by the national oil company (NOC) of the country. The NOC also commonly enjoys some preferential benefits (e.g. carried interests or back-in rights). PSAs are favoured by many developing countries. Since the first one was signed by U.S. independent IIAPCO in 1966 with the government of Indonesia these have become popular with developing nations because they retain title to reserves and are able to share in the revenues from risk investments without taking the financial risks. Disputes are dealt with under contract law. IOCs receive their rewards for taking upstream risks and making investments in terms of remuneration allocated from shares of field production. Fiscal mechanisms that determine how production is shared vary significantly from country to country, but usually involve distinctive elements relating to profit and to cost recovery. Most PSAs involve exploration and production phases (exploration and production sharing agreements, called EPSAs), but some (e.g. Qatar) are signed to cover development of already discovered reserves (development and production sharing agreements, called DPSAs). Some PSAs attempt to achieve fiscal stability by either allocating tax and royalty payments to be made only from the government's share of production, or including a fiscal stability clause. A signature bonus, which can in some cases amount to several hundred million dollars, is usually paid by the IOC to the government on the effective (signature) date of the PSA.

3. ***Service contracts*** are the least favoured by the IOCs, because they are engaged to perform development work on a financial fee basis (cost plus an agreed rate of return), without the opportunity to share in the upside revenues from long-term field production.

4. ***Hybrid contracts*** between PSA and service types that link the IOC's fee to production performance and revenues are operated by a few countries. These tend to place more technical and financial risk on the IOC than straight service contracts, but severely limit their long-term participation in successful ventures by the IOCs with production entitlements ceasing once the contractually agreed rate of return is achieved (e.g. Iran's buy-back contracts). Moreover, operatorship usually reverts to the NOC once the field or facility come onstream and the IOC ceases to have control of the project providing it with future revenues through to payout.

Not all countries operate just one or other of these types of systems, nor do they stick rigidly to one set of rates for the fiscal instruments applied as new contracts or leases are awarded to industry participants. In Nigeria, for example, projects operating under the first three of the system types identified above are all active. Moreover, countries may operate several contracts with different PSA mechanisms for historical, geographic or variable risk or cost reasons.

Fiscal Elements are Adjusted as Provinces Mature & Market Conditions Change

Fiscal elements in many systems are varied periodically in association with licensing rounds and lease sales, in which new licenses are awarded for the first time to industry participants. Fiscal changes are typically applied to only those permits awarded in the new rounds and are not retrospectively applied. Such a change was introduced in Nigeria in 2005 associated with deepwater PSAs where early licences prior to major field discovery were subject to lenient terms (low tax and royalty rates) to encourage investment. Following the discovery of major fields and higher market prices, terms have been toughened in subsequent licensing rounds.

Introduction, adjustment and removal of fiscal incentives has also occurred in the Gulf of Mexico deepwater leases which were subject to various royalty reliefs linked to water depth through to 2008 in order to promote investment in high-cost, technologically challenging areas. Those royalty reliefs (tax holidays) were based on sliding scales of cumulative production and water depth (e.g. in excess of 800 metres water depth the royalty relief applied to the first 87.5 million barrels produced). Once that production threshold is exceeded the royalty paid in deepwater production was applied at a reduced 12.5%. These reliefs were generally credited with stimulating industry activity in the deepwater Gulf of Mexico exploration and field development.

These royalty reliefs were progressively removed from Sale 206 as the province became more mature/successful, market prices increased on the basis that competition for new leases was strong enough, and there was a perception that the industry no longer needed incentives to encourage investment. Firstly the deepwater royalty rate was increased to 16.67% and for leases offered in the 2008 Central Sale 206 the royalty reliefs were removed and the royalty rates for blocks to be leased in all gulf water depths were increased to 18.75% from 16 .67%. The revenue-sharing provisions of the Gulf of Mexico Energy Security Act of 2006 (GMESA 2006) were also applied to Sale 224 leases. These enabled the states of Alabama, Mississippi, Louisiana, and Texas to share in 37.5% of the high bid bonuses paid on whole and partial blocks in the eastern Gulf of Mexico planning area and to share in 37.5% of all future government revenues generated from the acreage to be leased in that eastern planning area. In Sale 206 the U.S. Department of the Interior's Minerals Management Service (MMS) received 1,057 bids from 85 companies on 615 tracts and attracted $3,677,688,245 in apparent high bids, setting a record in U.S. leasing history for high bids since area-wide leasing began in 1983, MMS reported. Clearly the tougher fiscal terms had not deterred many companies from wishing to participate with BP, ConocoPhillips and Chevron being among the top 5 bidders.

Oil & Gas Industry has Embraced PSAs in Many Developing Countries

PSAs are now commonly employed for the exploration and development of large fields in the developing world, and are frequently associated with high political risk countries. They are not however embraced by all developing nations. Several OPEC countries refuse to entertain them (e.g. Saudi Arabia, Kuwait and Iran) and a fierce debate ensued in Russia, which adopted a few PSAs in the 1990s (e.g. Sakhalin-I and II), but President Putin essentially rejected them in 2004 in favour of a tax system that enables the government to more easily adjust (generally upwards) its take and control large industry projects of strategic interest in line with market conditions.

The IOCs have moved full circle in their attitude towards PSAs. When they were first introduced in the 1960s in Indonesia major IOCs resisted signing them, because of fears that they would too severely dilute their control and access to reserves. By the late 1990s IOCs actively requested PSA structures in preference to mineral interest arrangement, because they offer better guarantees of fiscal stability (e.g. Russia) and resistance now comes more from governments wishing to retain the ability to adjust fiscal elements over the production cycle.

Ranking Fiscal Systems by Government Percentage Take is Much Too Simplistic

Indices that attempt to rank the severity or otherwise of fiscal terms in a country (i.e. what percentage of project returns accrue to an industry participant and what percentage accrues to a government) should take such complexities into account, but rarely do so. This issue will be addressed in more detail below. Considering fiscal payments in such simplistic percentage "take" terms fails to take into account:

- Non-fiscal terms, risks and issues that influence project value.
- Field size expectation and environment.
- Time-value issues impacting revenues and costs differently.
- Flexible scales and triggers for specific fiscal elements.
- Variable market conditions (oil and gas prices, demand).
- Country track records in respect of fiscal stability.

These issues will be addressed in more detail in Section 2.3 of this report, but in terms of understanding some key issues and concepts associated with fiscal mechanisms it is useful to do so initially in terms of simple percentage takes by IOCs and government.

Progressive versus Regressive Fiscal Elements and Designs

A ***progressive fiscal system*** is one in which as profits go up, either due to lower costs or higher revenues derived from higher product prices, a government's fiscal take in percentage and absolute terms increases. As project profitability decreases, however, either due to higher costs or lower revenues derived from lower product prices, a government's fiscal take in percentage and absolute terms should also decrease.

A ***regressive fiscal system*** is one in which as profits go up, either due to lower costs or higher revenues derived from higher product prices, a government's fiscal take in percentage terms goes down although in absolute terms it may increase. More importantly, as project profitability decreases under a regressive fiscal system, either due to higher costs or lower revenues derived from lower product prices, a government's fiscal take in percentage terms increases even if in absolute terms it decreases.

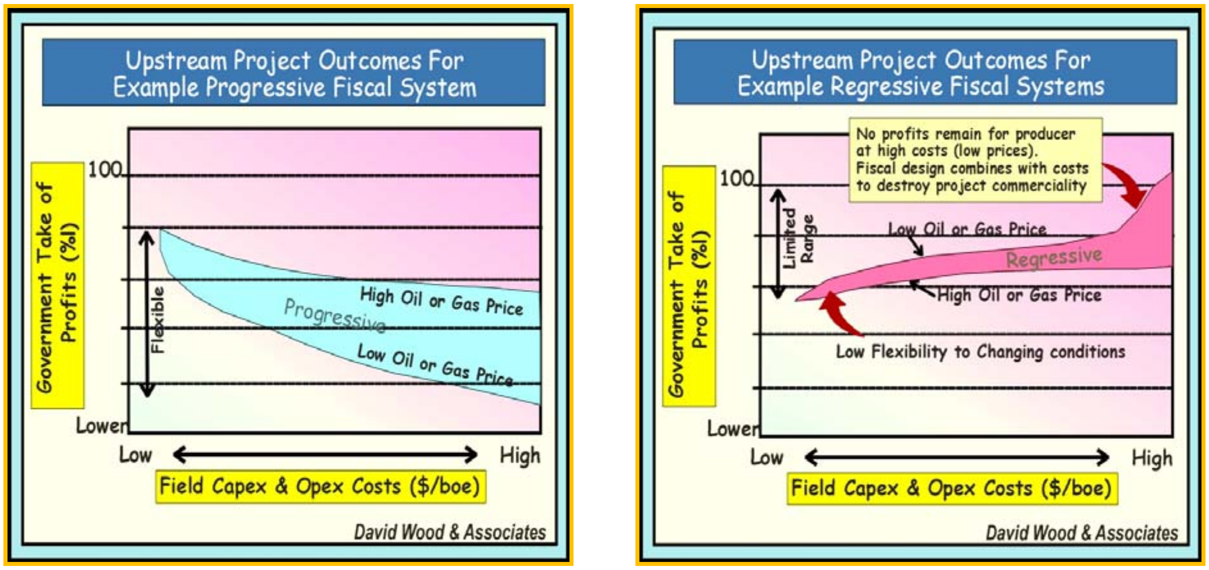


Figure 2.2.2 Regressive and Progressive Fiscal Design

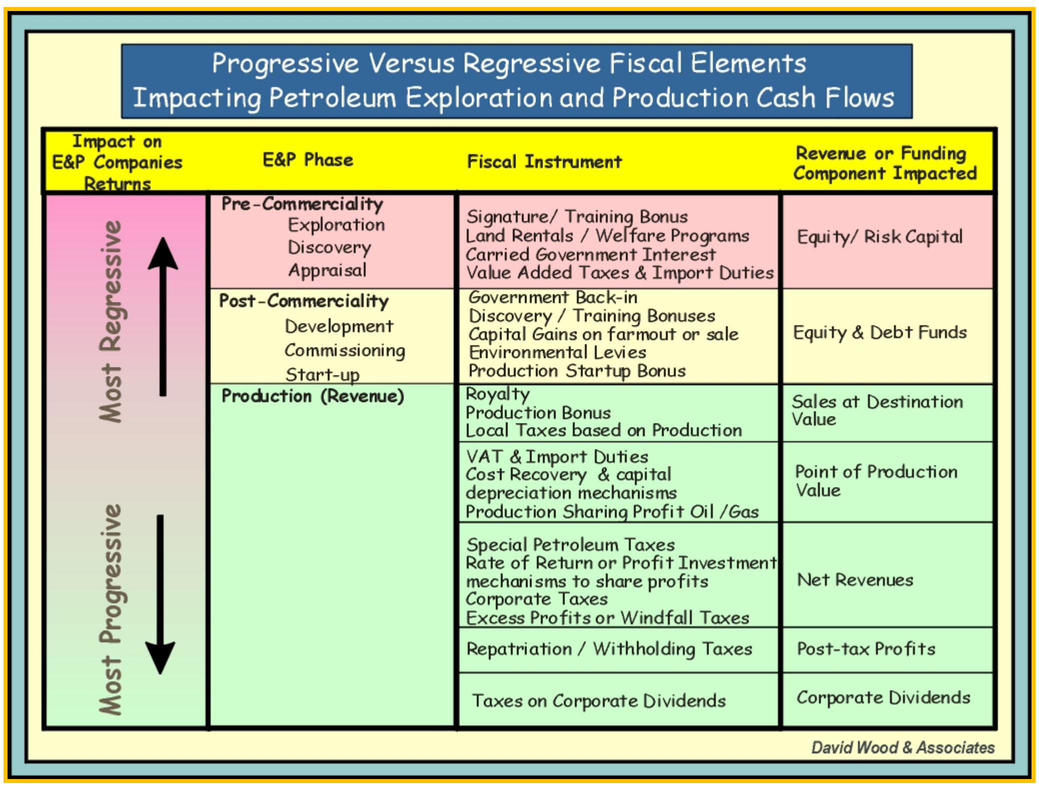
In extremely regressive fiscal systems government takes can exceed 100% of project revenues where production and other bonuses are contractually required independent of the revenue stream (some high-take production sharing agreements behave in that way). On the other hand, it is possible in quite high state-take systems for small- or medium-size fields to be commercial, if progressive and flexible fiscal designs are applied.

Figure 2.2.2 compares government percentage takes from progressive (left) and regressive (right) fiscal designs over a wide range of oil and gas prices and capital plus operating costs.

A practical example of comparing a more progressive with a more regressive fiscal system would be to contrast the state take derived from the Alaska fiscal system prior to the 2006 changes (i.e., ELF-driven) with the prevailing post -2007 fiscal design (more progressive combined progressivity tax, CPT-driven). Over much of the cost range (i.e., operating costs plus capital costs) the CPT-driven design at high prices takes a higher percentage of profits than the former ELF-driven regressive design. However, at very high costs the regressive system moves progressively to take a higher percentage of profits whereas the more progressive CPT-driven regime decreases its relative take. The left diagram in Figure 2.2.2 reflects a design in which high prices drive toward a higher percentage take (the prevailing CPT-driven Alaska system is not as progressive as this on the high cost side because of regressive royalty, property tax and production tax floor elements); the right diagram in Figure 2.2.2 reflects a design in which low prices and high costs drive toward a higher percentage state take.

As fiscal systems become more regressive the threshold field size for commerciality to be achieved increases and breakeven product price for a project also increases. A general rule for fiscal elements levied on production, which is illustrated in Figure 2.2.3, is that the closer to the bottom line (net position in accounting or cash-flow terms) a fiscal deduction is applied the more progressive it is. Conversely the closer the fiscal element levied is to destination value revenues the more progressive the impact of a tax credit or allowance (e.g. relief or holiday) applied to it.

In times of high gas price and with large gas fields few worry about regressive taxes. In the case of high-cost (e.g. deepwater, remote from markets and/or infrastructure, high latitude/Arctic or marginal reserves fields) or low-price environments regressive taxes can make the difference between a project being commercial or not. As most fiscal designs involve the integrated effect of several fiscal elements a sensitivity model evaluating performance under a range of costs and product prices is required to establish whether the overall fiscal system is highly progressive, mildly progressive, fiscally neutral, mildly regressive or highly regressive.



Progressive Versus Regressive Fiscal Elements Impacting Petroleum Exploration and Production Cash Flows

Impact on E&P Companies Returns	E&P Phase	Fiscal Instrument	Revenue or Funding Component Impacted
Most Regressive	Pre-Commerciality Exploration Discovery Appraisal	Signature/ Training Bonus Land Rentals / Welfare Programs Carried Government Interest Value Added Taxes & Import Duties	Equity/ Risk Capital
	Post-Commerciality Development Commissioning Start-up	Government Back-in Discovery / Training Bonuses Capital Gains on farmout or sale Environmental Levies Production Startup Bonus	Equity & Debt Funds
	Production (Revenue)	Royalty Production Bonus Local Taxes based on Production	Sales at Destination Value
		VAT & Import Duties Cost Recovery & capital depreciation mechanisms Production Sharing Profit Oil /Gas	Point of Production Value
		Special Petroleum Taxes Rate of Return or Profit Investment mechanisms to share profits Corporate Taxes Excess Profits or Windfall Taxes	Net Revenues
		Repatriation / Withholding Taxes	Post-tax Profits
Most Progressive		Taxes on Corporate Dividends	Corporate Dividends

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Figure 2.2.3 The higher in the tabulated list a fiscal element appears the more regressive its impact on overall fiscal design.

Figure 2.2.4 identifies the main regressive and progressive fiscal elements. The elements become more progressive toward the right of that diagram. However, a government also takes more risk that it might never receive revenues from the more progressive fiscal instruments (e.g. if a project fails to reach profitability thresholds).

The regressive impact of a royalty as a fiscal element is a consequence of the royalty being deducted as a percentage volume of production at the point of production from each volume of oil or gas produced regardless of whether it is sold profitably or not. A point of production value with royalty deducted may remain positive as only TT&T costs are deducted from a destination value in such a computation. However, the net value (i.e. PTV in Alaska) may become negative when all upstream costs are taken into account due to the impact of the royalty (or in Alaska terms a "loss carryforward" would result instead of taxable PTV.)

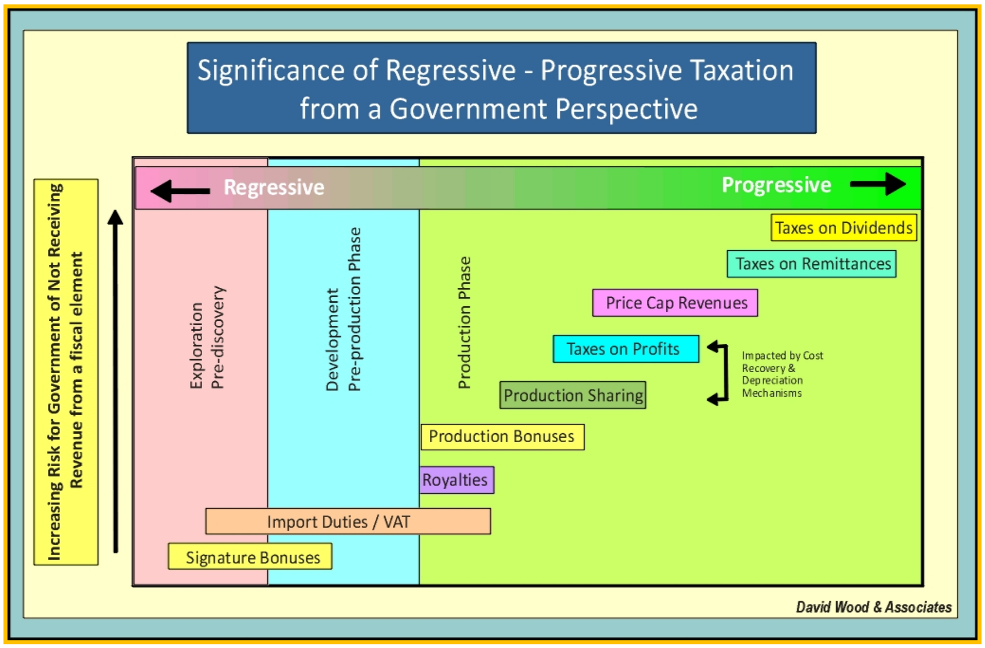

Figure 2.2.4 Regressive versus progressive fiscal elements and government risk. The further to the right the more progressive the instrument, but also the later in the field production cycle that a government receives its share.

This regressive impact of a royalty is illustrated in Figure 2.2.5 for a range of natural gas prices:

- $10/mmbtu, a 20% royalty accounts for 50% of the gross profit for a remote gas field costing $6/mmbtu to produce and deliver long-distance by LNG or pipeline to a consuming gas market.
- $15/mmbtu, the royalty share of profit decreases to 33.3%.
- $20/mmbtu the royalty share of profit decreases to 28.6%.

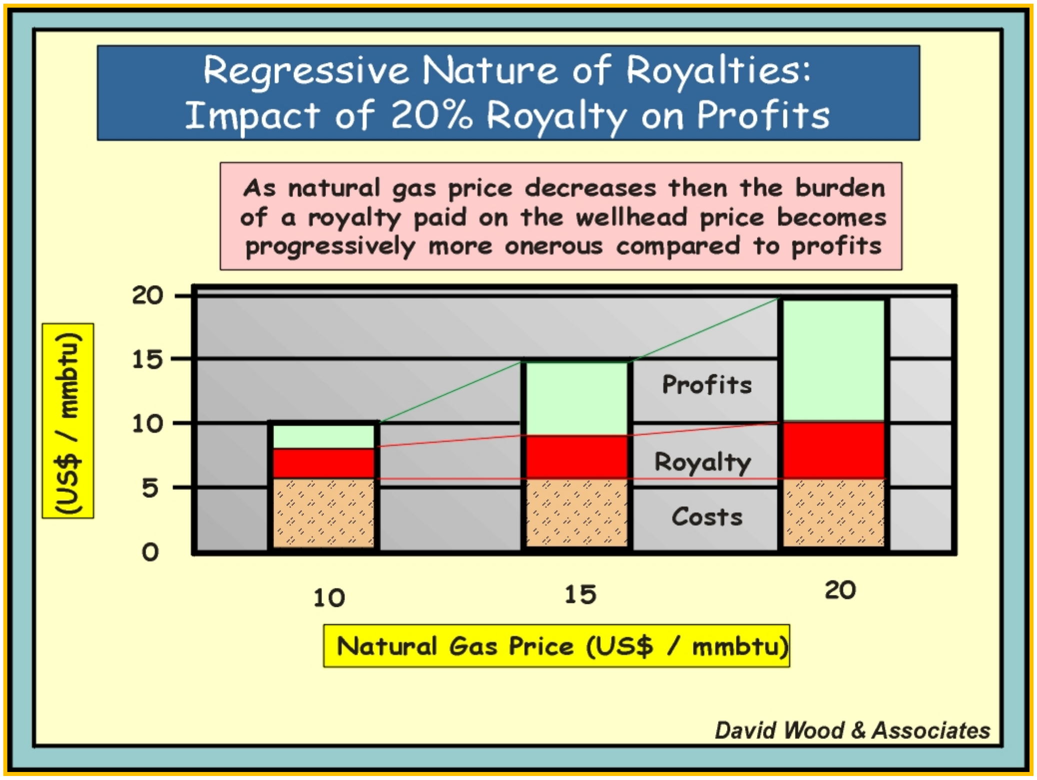

Figure 2.2.5 The regressive impact of royalty results in a royalty representing a higher proportion of project profit at low product prices than at higher prices.

Figures 2.2.6 and 2.2.7 illustrate how the same cumulative government take can be achieved with either a regressive or a progressive fiscal design.

It is apparent from Figures 2.2.6 and 2.2.7 that regressive fiscal designs should provide governments with earlier and less risky revenue stream which would have greater value on a discounted basis (i.e. taking into account the time-value of money).

However, regressive fiscal systems provide IOCs with lower discounted values than progressive systems for the same field development and have a higher risk that marginal field discoveries might not be developed. This may dissuade some IOCs from committing to exploration or large capital investments in volatile market conditions and in regions of high political risk.

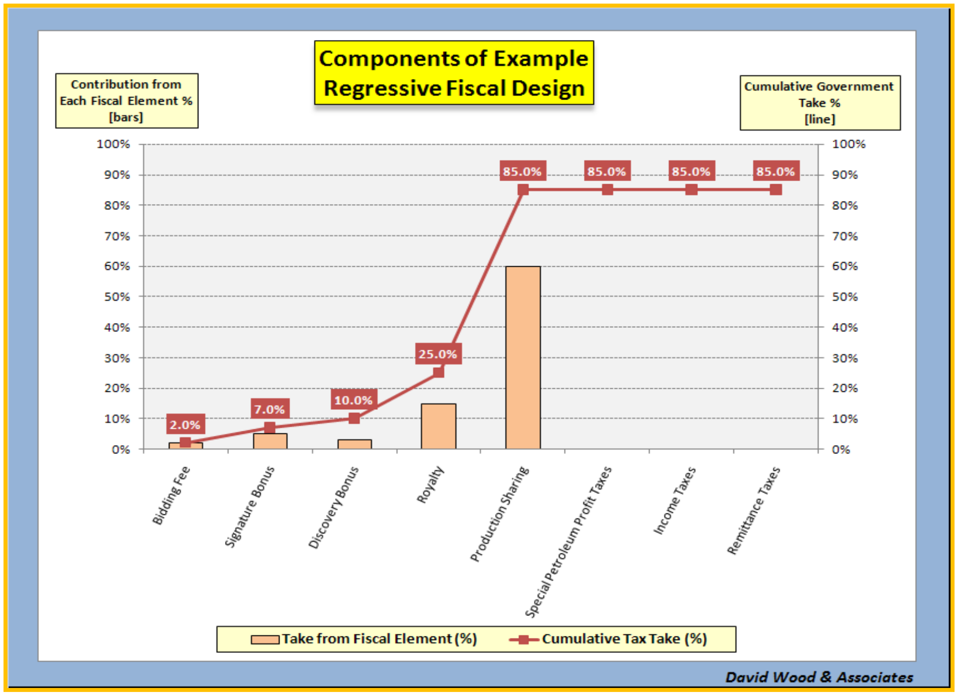

Figure 2.2.6 A regressive fiscal design yielding 85% cumulative government take.

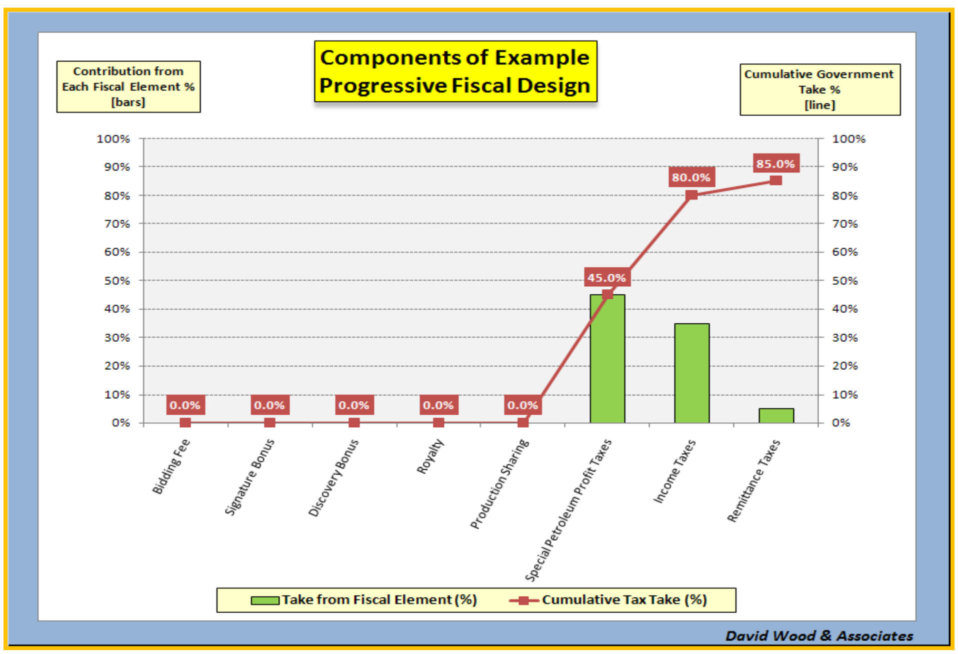

Figure 2.2.7 Fiscal elements of a progressive fiscal design yielding 85% cumulative government take.

Economic and Commercial Fiscal Design Issues Impacting Upstream Project Returns

There are many other specific commercial issues in addition to overall percentage take that require consideration under upstream fiscal designs. All of these issues can impact contract or project values and returns from the opposite perspectives of governments and producers. They are listed and ranked below approximately in descending order of their potential negative impact on an IOC's profit share from an upstream field development project (i.e. their ability to erode the IOC's profit share).

- Low production or profit share.
- High rates of regressive taxation elements (e.g. royalty & bonuses).
- Lack of tax stability guarantees and track record of adverse tax changes.
- Fiscal elements not paid from government's share of production (in PSAs).
- Substantial equity participation, carry or back-in by state or NOC.
- Pre-emption rights of NOCs and governments in sales and assignments of interest at prices less than fair market value.
- Low cost recovery (oil or gas) allocations (<=50% in PSAs).
- Slow depreciation (DD&A) mechanisms for capital costs.
- Domestic market supply obligations for percentages of production at subsidised prices.
- Access to existing infrastructure (e.g. transmission pipelines) at tariffs above market rates or limited by control of monopoly competitors.
- Oil and gas prices indexed to government posted prices not international benchmarks.
- Price caps that take effect at low price thresholds and severely limit profit shares accruing to IOC above those prices.
- Introduction of windfall profit taxes when high product prices prevail.
- High signature and bid bonuses acting as barriers to entry for smaller companies.
- Exclusion of genuine expenditure items from capital cost recovery pool.
- Exclusion of interest payments on project debt as a cost recovery item.
- Ring-fencing of costs available for recovery around specific fields or licences.
- Imported goods subject to high customs duties, local & value-added taxes.
- High property taxes imposed on essential land-based production facilities.
- Payment for product sales in local currency prone with obligations to exchange that currency at artificially high government-posted exchange rates.
- High interest rates on local deposits excluded from cost recovery allowances.
- Slow and administratively onerous planning approval process for field development and facilities construction.
- Procurement constraints that insist upon local inexperienced or inadequately skilled contractors.
- Substantial government interference in award of procurement contracts.
- Constraints on skilled expatriate employment where local staff skill levels are inadequate for the tasks to be completed.
- Agreements subject to national rather than international law and litigation.
- Lack of recourse to international arbitration and clear dispute and default resolution terms (e.g. withering clauses) focused on the principles of best international industry practices and of time being of the essence.
- Lack of a clear unitization mechanism and timeframe (if required).
- No-flaring rules associated with harsh penalty payments for any that occurs.

- Lack of legislation for associated gas with prevailing profit-sharing mechanism focused on oil or natural gas liquids.
- No local market for gas or local gas prices pegged at artificially low (subsidized) levels.

The exact order of importance of the above list will depend upon local circumstances, track records of historic upstream projects in the country and specific contractual or licence obligations. In many cases such terms will not be negotiable and must be either accepted or rejected by an IOC. Nevertheless, their impact on an IOC's perceived risked value of a contract or permit should not be overlooked in the fiscal design process.

Minimum Commercial Field Size and Environmental Considerations

The expected size of the oil and gas fields either discovered or yet-to-be found, the depth to its reservoir, its reservoir quality and its physical location (e.g. remote difficult terrain, deepwater etc.) and a host of other technical factors associated with specific oil and gas fields will determine, along with the fiscal mechanism, the minimum reserve size required for a commercial development. This may vary greatly from area to area and contract to contract, as illustrated in Figure 2.2.8, and is only partly determined by fiscal design. Very small onshore fields under fiscally-lenient and progressive mineral-interest systems (e.g. taxes on profits and very low or no royalty) can be commercial, as costs are at the low end of the spectrum and fiscal take is limited to profit-making scenarios. On the other hand in deepwater, remote and harsh climatic areas where development costs are high the minimum commercial field size will be much higher. Irrespective of the fiscal design minimum field size may depend upon cost and location issues (e.g. distance and access costs to existing infrastructure).

As environments get harsher and more remote and/or fiscal systems get more regressive the minimum reserve size of a commercial field will increase. In terms of reducing the minimum field size that might be commercial in a given environment a government could reduce its take of profits or to some extent make its fiscal design more progressive (e.g. Alaska 2006 and 2007 introduction of investment credits).

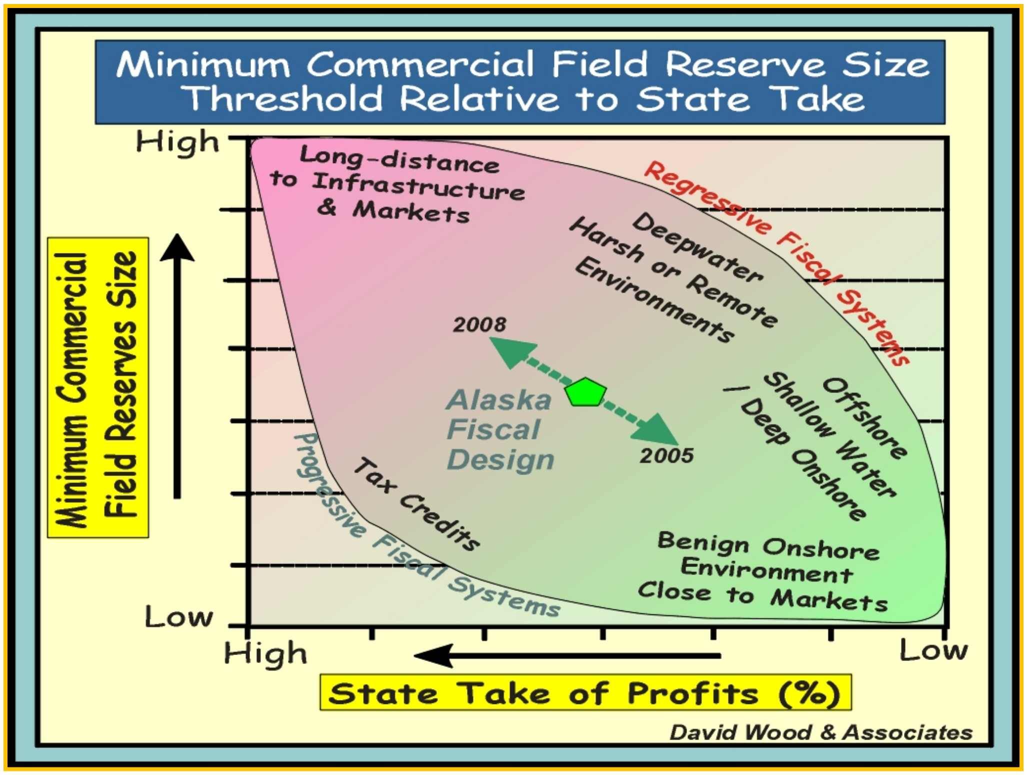

Figure 2.2.8 Minimum commercial field size in a petroleum province depends upon a range of factors, one of which is fiscal design. Minimum field size for commerciality has increased due to changes introduced to Alaska's fiscal regime in 2006 and 2007 due primarily to the increase in basic production tax. Under provisions of the former ELF mechanism the smallest fields paid no taxes. Royalties, property taxes and floor payment provisions to production taxes are regressive elements of the prevailing Alaska fiscal design which influence the minimum commercial field size. Small producer tax credits do help to improve the commerciality of some fields, but for many small fields in Alaska such credits are unable to compensate for the impacts of the high-cost arctic environment and regressive fiscal elements.

A number of more specific technical issues associated with long-term reservoir performance also need to be considered when establishing appropriate fiscal designs to enhance commerciality and introduce appropriate fiscal controls and incentives. These include, but are not limited to:

- Maximizing recovery of LPG and NGL and establishing local markets for such products;
- Identifying the key reservoir performance risks.
- Field development options available to mitigate those risks (additional well testing or higher-resolution seismic data, developing the field in stages, use of floating versus fixed offshore production facilities, etc.).
- Establishing the primary reservoir drive mechanism, production decline rates and expected pressure depletion and water cut trends.

- Evaluating secondary and tertiary recovery and pressure support requirements and their costs.
- Considering potential to use facilities deployed as a production hub.
- Emissions constraints (e.g. no gas flaring, water and well cuttings injection for disposal, and carbon sequestration) and their costs.

Introducing Flexibility into Fiscal Design – Sliding Scales

It is true that flexibility often requires and introduces complexity into a fiscal design, but the advantages gained usually outweigh the disadvantages of administering and modelling more complex systems. Fiscal systems ideally should be simple, but need to retain sufficient flexibility to avoid leading to highly regressive systems that inhibit investment in small or high cost fields.

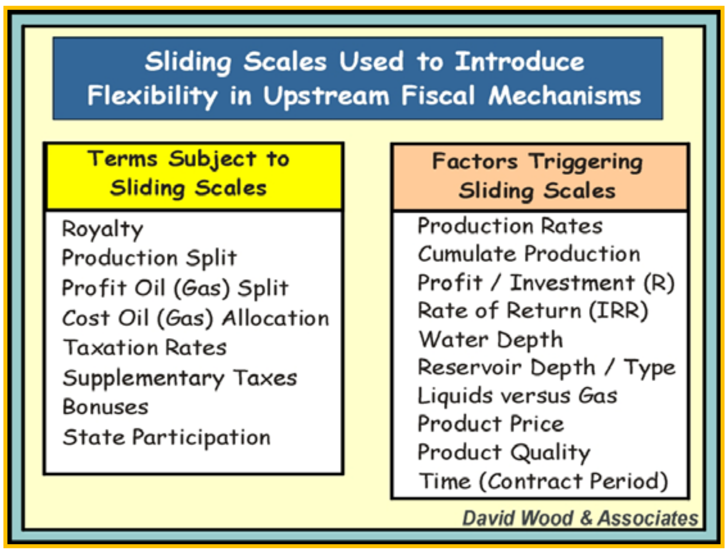

Figure 2.2.9 Sliding scales for fiscal elements and their triggers.

At the exploration stage fiscal terms need to be as flexible as possible to attract investors. This is because prior to drilling the size and nature of potential fields is highly uncertain. The most common method for introducing flexibility into fiscal contracts is with sliding scale terms. These yield progressively smaller shares of profit to the contractor as economic returns from a field improve. Daily production rates are the most common trigger used in PSA sliding scales. However, some contracts tie more than one fiscal element to sliding scales and the scales may be triggered by a wide range of metrics (Figure 2.2.9).

In Nigerian PSAs the increasing petroleum profits tax sliding scale is linked to cumulative oil produced.

Figure 2.2.10 illustrates a sliding scale for profit sharing from gas and NGL production that varies from 35% to 15% to the IOC depending upon 10,000 boe/day production rate tranches. The sliding scales usually operate on increments of production. If daily production is 15,000 boe/day of either/or both gas and gas liquids, then 10,000 boe/day are subject to a 35% profit split and the remaining 5,000 boe/day are subject to a 30% split.

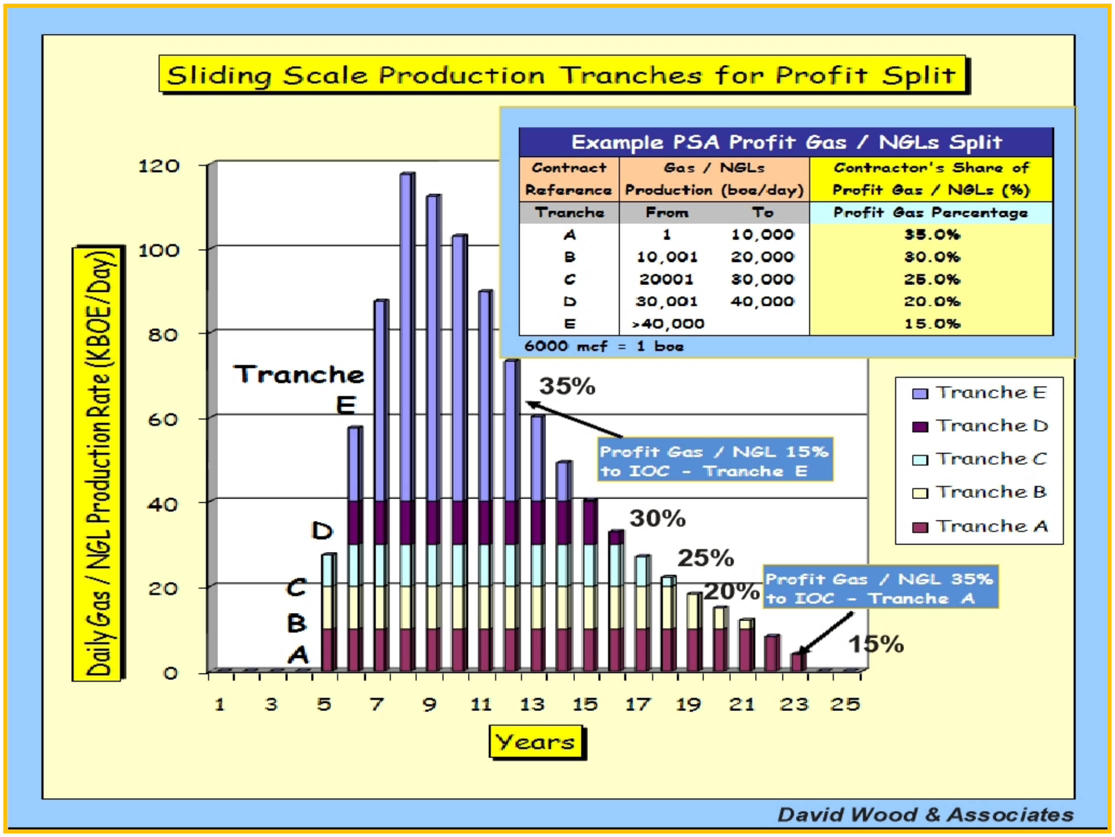

Figure 2.2.10 A gas-condensate field production profile illustrating how tranches of production barrels of oil equivalent terms are subjected to different splits contractually defined within a PSA.

In some fiscal systems a revenue/investment ratio (or profit/investment ratio) referred to as an R-factor is used as the trigger for profit splits and rate bands of other fiscal elements. Investors' rate of return (IRR) is also widely used as a trigger for different rate bands. Such mechanisms can be highly progressive, but require significant administrative and expenditure audit effort to ensure that costs are appropriately allocated and to avoid creative accounting (or "gold-plating" as it is sometimes referred to). R-factor and IRR mechanisms are prone to manipulation (by both Government and IOC) by excluding certain costs or inflating them depending upon a party's objective. In some cases under such terms decisions on the timing of expenditures may be driven by the fiscal mechanism (i.e. avoiding a move into a lower-profit tranche) rather than by best technical practice.

There is a philosophical debate concerning whether a fiscal system ought to passively take a share of the economic rent rather than change economic decisions that are sub-optimal and should be avoided. A case can be argued for the opposite approach where a fiscal system is specifically designed to affect decision making and actively encourage companies to invest in certain industry sectors by granting them incentives. A strategic decision has to be made regarding each fiscal instrument and the overall fiscal design concerning its ability to reward investors for taking desirable actions (e.g. investments) and punishing investors for taking actions against the interest of the state or the long-term performance of a producing asset (e.g. failing to use best practices to control costs).

The ability to introduce tax incentives to stimulate exploration and incremental development activity, and to be able to remove those incentives when they have achieved their goal, is important and one of the reasons for retaining the ability to modify fiscal design over time and not lock into a set of fiscal instruments for many decades. This fits with the case for rewarding investors that have taken positive (in the eyes of the state) actions, or promoting them to take actions in line with a state's new strategic objectives. Clearly investors have to make judgments regarding the timeframe that such incentives are likely to be applied by a government. Also investors require some confidence that once the government has secured their investments it is not going to subsequently remove those incentives or impose retrospective higher tax or royalty rates such that expected returns from those investments will be substantially diminished rendering some developments uneconomic from the investors' perspectives. The fiscal credibility of a government is important in terms of the judgments that investors are likely to make when offered fiscal incentives.

There are fiscal instruments, e.g. those in which higher tax rates (or additional taxes) kick-in when certain levels of profitability or return on investment are achieved, or certain ring-fence restrictions that may influence how, where and when expenditures are made by an operator, irrespective of whether such decisions are in the best interests of the asset or the state on technical and commercial grounds. Such systems can lead to inefficiencies and in extreme cases expenditures being wasted or poorly targeted. For a government trying to influence positive actions such fiscal instruments can be counter-productive.

Some question whether incentives really work or are cost effective in prompting an action (development) that otherwise would not have occurred. It is certainly possible to give away too much and get little in return, such as countries that fund new facilities to host a major sporting event, but fail subsequently to recover enough tax revenue to cover the incentives (a dilemma London is wrestling with in respect of 2012 Olympic Games). There are examples of where incentives do work to achieve their strategic intention, e.g. deepwater exploration Gulf of Mexico in the 1990s, and Norway attracting independent companies since 2003 (discussed in detail in Section 2.5) are examples of where incentives have successfully attracted investment. However, some luck and good quality assets are required for these to create sustained interest and long-term value in the form of fiscal revenue, which incentives cannot be guaranteed to provide. By luck I mean for example early success in exploration programs stimulated by incentives. Incentives also need to be adjusted from time to time to focus them toward particular sectors of the industry and to reflect market conditions.

Adjusting the Pace of Cost Recovery and DD&A

Time-value considerations are never as important as when discussed in terms of cost recovery. As the IOC is providing the capital investment for a field development (sometimes with the NOC or government as an equity partner either carried or paying its share later out of production) the faster that investment (sunk costs) can be recovered from revenues generated from early production, the higher the discounted value of the project.

The pace at which costs are recovered is determined by the cost gas/oil allocation (in PSAs) and the amortization schedules for specific types of costs (i.e. exploration, development or operating costs with development costs often divided into specific categories associated with types of facilities or materials precisely defined – tangible, intangible, etc). Amortization schedules are either specified in a PSA or the fiscal regulations applied to mineral-interest systems. Such amortization schedules may vary from fiscal element to element, e.g. cost amortization rules for special petroleum taxes or PSA terms may be different from those applied to income to calculate corporate taxes. Moreover those fiscal amortization schedules are usually different from those applied under GAAP rules for accounting purposes. A general rule is that the lower the cost gas/oil allocation percentage in a PSA and the longer the amortisation period for capital costs the slower the pace of cost recovery.

Alaska employs four different cost-recovery schedules in its current fiscal design: Instant expensing for production tax (which is attractive from a producer's perspective), Asset Depreciation Range (ADR) for Alaska CIT (which is slow cost recovery), modified accelerated cost-recovery system (MACRS) for federal CIT (which is generally faster than ADR), and a reserves based schedule for property tax (which is linked to the pace of field depletion similar to unit of production mechanisms). Although not strictly a cost recovery mechanism, investment and loss carry forward credit certificates must be applied over yet a different time frame, namely two years. Such a diversity of mechanisms within the one fiscal design is unusual and increases (some would say unnecessarily) the complexity of the overall fiscal calculation.

A comparison of Figures 2.2.11 and 2.2.12 illustrates why for cash flow reasons (even though it might negatively impact investment) governments prefer slow IOC cost recovery mechanisms, as more production is then allocated to profit sharing in the crucial early years. This results in higher value and more cash flow in the early years of production for a government. This is because a government only receives funds from the profit component of revenue and not the cost-recovery component. PSAs with 100% cost-recovery allocation can result in a government not seeing any revenue from several early years of production as IOCs take all that revenue to recover their sunk costs (e.g. 1993 PSAs in deepwater Nigeria).

IOCs prefer fast cost-recovery mechanisms as the discounted values of projects are increased substantially and payback times are reduced, thereby reducing financial exposure risks as well as improving value. PSAs with cost gas/oil allocations of less than 50% (of revenue less royalty) and amortisation schedules of more than 5 years (for field development costs) are considered as having slow cost recovery mechanisms. Figure 2.2.13 illustrates the ranges of cost-recovery allocations to be considered in production sharing systems.

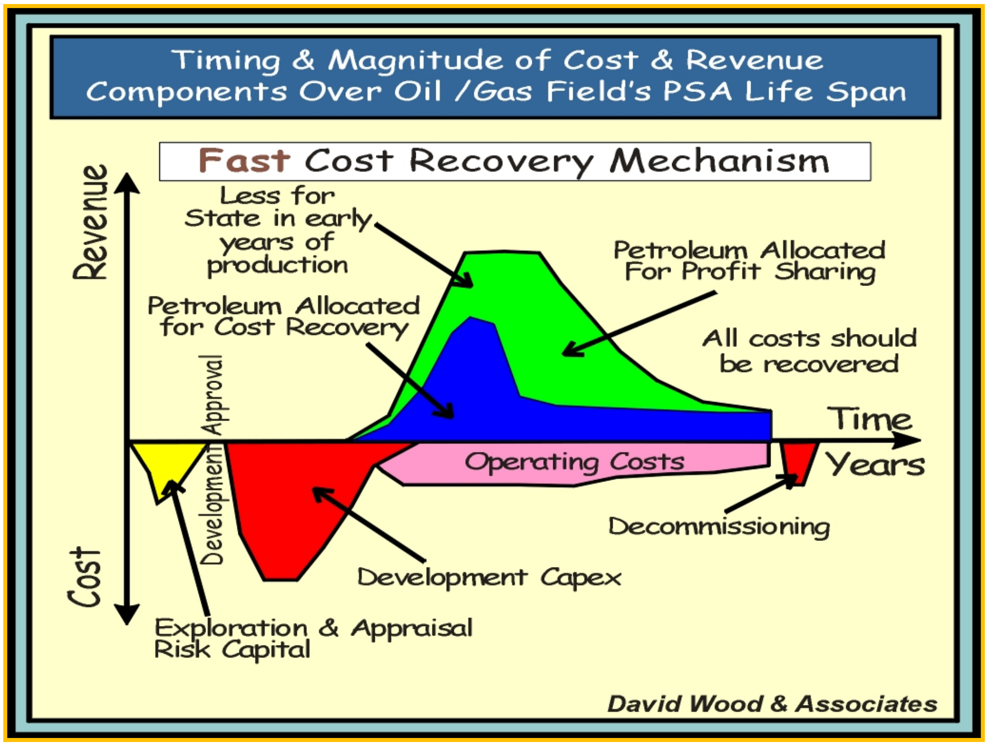

Figure 2.2.11 Impact of fast cost recovery mechanism on division of revenues.

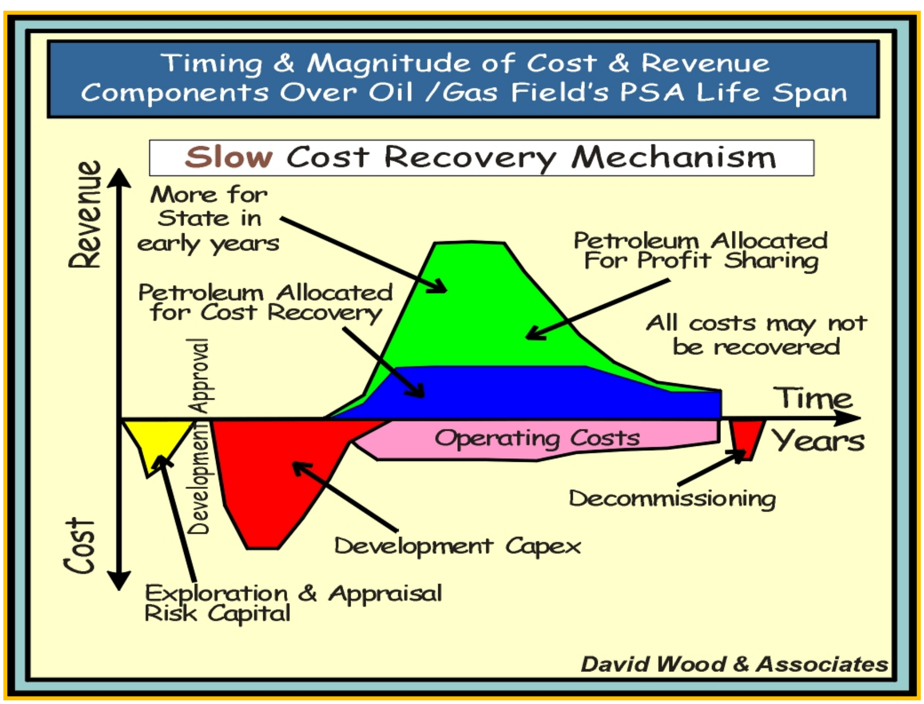

Figure 2.2.12 Impact of slow cost recovery mechanism on division of revenues.

The issue of how and if decommissioning costs are tax deductible or recoverable varies from country to country. Frequently the contract term ends while the field and facilities retain commercial life for the government. Hence field abandonment and decommissioning may be dislocated in time beyond the life of a licence or PSA term.

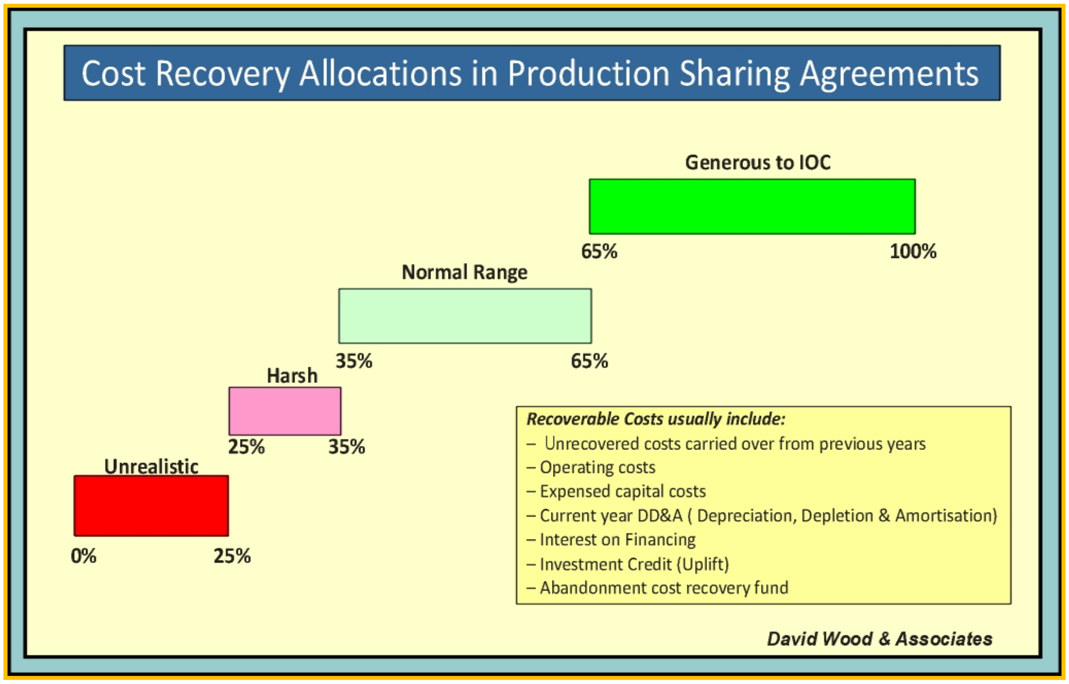

Figure 2.2.13 Maximum cost recovery allocation levels specified in production sharing agreements vary widely. Categories of costs that are allowed for recovery also vary and are usually recovered subject to depreciation restrictions. The percentage ranges displayed in this diagram refer to the percentage of revenue made available from which costs may be recovered. In all cases 100% of allowable costs will ultimately be recovered, but this will occur more slowly if the allocation percentage is low and more rapidly if the allocation percentage is high.

Integrated Upstream and Midstream Projects

Production and cost recovery for many large gas fields are characterised by approximately flat profiles spread over many years, due to long-term contractual quantities and price indexation specified in the gas sale and purchase contracts (e.g., gas liquefaction project). Such projects require huge (i.e. multi- billion US$) upfront capital investments for upstream gas field development infrastructure, wells, gas and NGL processing, plus midstream facilities involving either export pipelines, liquefaction or gas-to-liquids (GTL) plant facilities. Some fiscal systems deal with these developments as integrated projects with both sets of costs to be recovered from the cost gas allocation.

Achieving project pay-back in a meaningful timeframe is often one of the key commercial challenges for the investors. Fiscal mechanisms that take into account the time-value issues can help the commerciality of such projects from an IOC perspective and encourage investment. For example, the Pearl GTL project currently under development in Qatar had, when initially negotiated, a fiscal mechanism (associated with a development and production sharing agreement, DPSA) involving a high cost gas allocation and a forward -weighted component (i.e. profit-driven fiscal element) to Shell's profit gas entitlement (Figure 2.2.14).

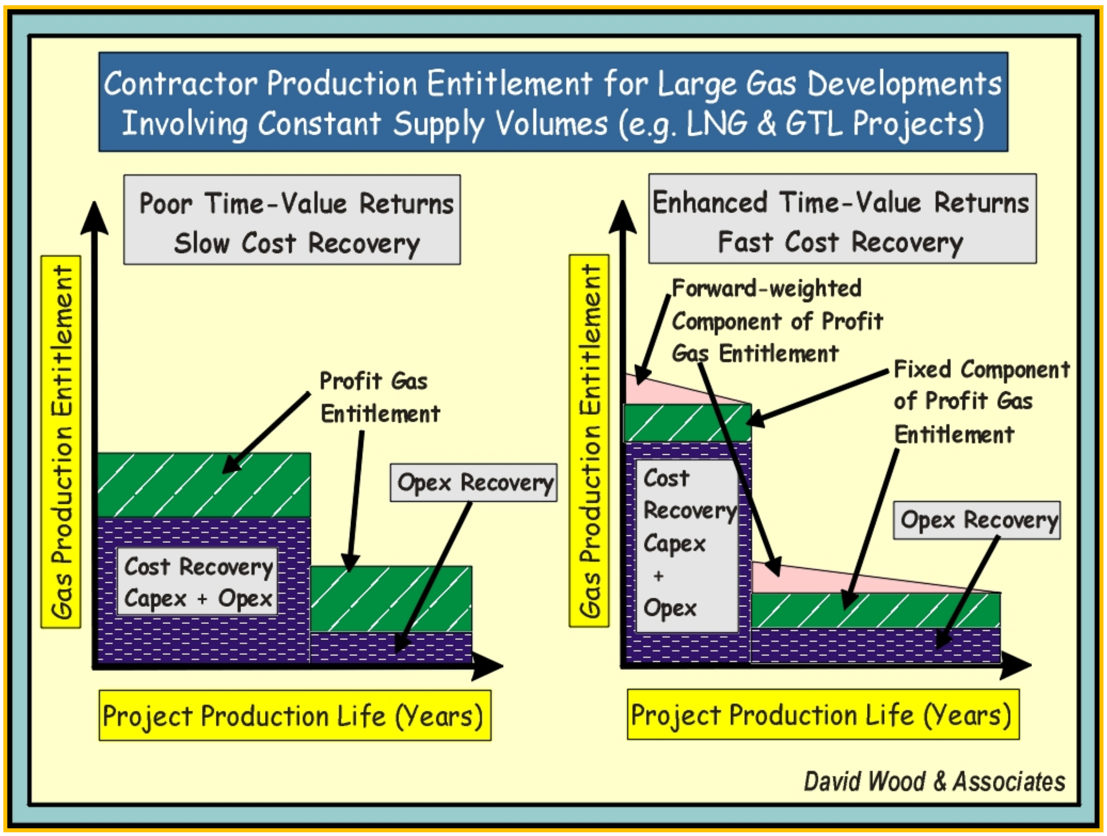

Figure 2.2.14 Gas production entitlements that vary with time or cumulative production.

Such a forward-weighted profit split mechanism enhances the discounted value to the IOC and at the same time gradually passes the major share of profit to the government. At the end of the contract period (usually some 25 years or more) the facilities, to which the government holds title, pass to the government or NOC for future operations. At the stage of hand-over the facilities should have many years of production life left from which the government then benefits on a 100% basis from all future revenues. Governments usually are able and prefer to take long-term strategic benefits and, for more developed nations, enjoy lower costs of capital than IOCs. Government's discount rates should therefore be lower than IOCs enabling them to also benefit from such a forward-weighted fiscal scheme. In negotiations such schemes usually involve a trade-off of higher early production shares to the IOCs for higher long-term shares accruing to the government.

Such schemes do not however come without risk for the governments, as the Pearl GTL project itself illustrates. Qatar's Pearl GTL project is an integrated project incorporating an offshore field development component, a pipeline and a land-based GTL facility. When the DPSA was originally negotiated (Qatar and Shell) in 2003/4 the project had a budget of some $2 billion for offshore work and $4 billion for onshore work. By early 2007 when the final investment decision was made the project budget was announced as having escalated to between $14 billion and $20 billion. Under the fiscal mechanism initially envisaged the government suffers from this massive cost overrun as its revenue share becomes substantially delayed whereas the IOC recovers the cost-overrun from the high early cost-recovery allocation. From the government perspective it is important to link forward-weighted fiscal incentives with clear budget limits. If those limits are breached then alternative cost-recovery mechanisms (less favourable to the IOC) should apply. Such an arrangement can motivate IOCs to improve their cost control.

Another challenge in such forward-weighted arrangements is keeping investors and IOCs interested in the project, and seeking expansion opportunities, during the latter part of the project cycle while the state is getting its piece of the action. The oil and gas portfolios of IOCs need to be balanced with a range of high-risk but high-reward projects and lower-risk but lower-reward projects. During the early payback years of large projects IOCs have huge financial exposures with capital tied up in the development of the assets. Such assets remain toward the high-risk end of the oil and gas asset risk spectrum until payback is achieved. Once payback is achieved an asset generally moves into a lower-risk category (this simplistic view ignores the many other residual risks, e.g. political risks, etc). Most IOCs recognize the value of such lower-risk assets. They are sometimes (somewhat optimistically, because most of the revenue accrues to the government) termed "cash cows" and IOCs are prepared to accept quite low-profit shares from them on the basis that minimal capital remains tied up in them. Once assets move into this later lower-return stage, some IOCs may elect to sell them to others that wish to expand the lower-risk production share in their portfolios. Reserves are also a consideration with IOCs always keen to be able to book large reserves volumes even if the return they achieve from their production is modest. Hence from a government perspective it is incorrect to assume that the latter part of the cycle in forward-weighted fiscal arrangements are of no interest to the IOCs.

Reserves Allocation Issues for IOC and Fiscal Designs

Reserves that can be allocated under specific fiscal designs are significant to companies registered or listed on U.S. stock exchanges and therefore subject to U.S. Generally Accepted Accounting Principles (GAAP) and Securities and Exchange Commission (SEC) reporting rules. Under mineral-interest mechanisms all of an IOC's working interest share in the proved reserves of a field may be booked as reserves. Under PSAs only the profit and cost gas/oil entitlements allocated to the IOC, plus any tax component paid on those shares may be booked. In some PSAs taxes on the IOC's production allocation are paid from the government's production share. The oil equating to such taxes may in some cases (depending upon the international tax treaties in place) also be booked as reserves. Such tax allocation to reserves is referred to as a "tax gross-up". Reserves booked for the same field subject to PSA fiscal designs are usually substantially less than if they were subject to mineral-interest designs.

The situation is even worse for service contracts, irrespective of whether the fiscal terms are harsh or generous, as the IOC is only remunerated from the revenue proceeds of a project. If a service contract grants an IOC no direct interest in production volumes then the SEC usually refuses to allow the IOC to book any reserves associated with that contract. The Philippine service contract is an example of such an arrangement, which is actually quite generous to the IOC in terms of revenue splits, but not from a reserves perspective. Booking reserves under service or hybrid contracts is usually not possible for IOCs as the fee paid to the contractor for the investment and work provided is not related to reserves, but is either remuneration of a financial arrangement or not linked to any ownership of production. The impact on reserves booking due to fiscal design and market conditions can be significant for IOCs pressured by reporting standards to demonstrate sustainable growth in their reserves base. It is one of several reasons that make service and buy-back type agreements unattractive to them.

Another adverse feature of PSAs for the IOCs and the reserves they are able to book occurs when substantial product price increases occur. This is due to the value of the cost gas/oil component which establishes the volume of reserves required at prevailing market prices to recover sunk and forecast costs. As prices go up the reserves volumes allocated to cost gas/oil allocation go down. This reduces the reserves that IOCs can book in their financial returns to the SEC. For some major IOCs the downward adjustments in recent years have been substantial and responsible for part of their apparent poor reserve replacement performance across their whole portfolio of assets.

The converse of this is a benefit to those governments operating mineral-interest fiscal mechanisms. These are of higher value to major IOCs as they can improve their apparent reserves-replacement ratios and the absolute volumes of reserves they are able to book.

Corporate Income Tax Rates

In most countries, in addition to fiscal instruments targeting production, gross revenue and net cash flow a producing company has to pay income tax on its earnings (net of the production taxes and royalty) in that country. There may be tax treaties in existence that enable the companies to offset income tax paid overseas against its income tax liability in its home country. In some states, such as Alaska, income taxes are calculated on an apportionment basis, taking into account worldwide earnings. Whatever the mechanics of the income tax calculation, there is no doubt that income tax rates are an important factor in determining the ultimate fiscal take from oil and gas producers and should be taken into account when restructuring the overall fiscal design.

Figures 2.2.15 and 2.2.16 compare state, federal and combined income tax rates in Alaska with other U.S. states and OECD countries in 2008. It is apparent that Alaska's combined rate is higher than the average of any OECD country, placing it close to the top end of the range. Alaska (41.1%) has higher combined state and federal corporate income tax rate than the average US rate (39.3%) and is more than 6% higher than Wyoming, the U.S. state with the lowest rate (35%). These high rates do have a significant impact on the total fiscal burden placed on producing oil and gas companies.

Figure 2.2.15 to Figure 2.2.17 see below.

Comparing U.S. State Corporate Taxes to the OECD, 2008

OECD Overall Rank	Country/State	Federal Rate 2008	Top State/Provincial Corporate Tax Rate	Combined Federal and State Rate (Adjusted) (a)
	Iowa	35%	12%	42.8%
	Pennsylvania	35%	9.99%	41.5%
	Minnesota	35%	9.8%	41.4%
	Massachusetts	35%	9.5%	41.2%
	Alaska	**35%**	**9.4%**	**41.1%**
	New Jersey	35%	9.36%	41.1%
	Rhode Island	35%	9%	40.9%
	Maine	35%	8.93%	40.8%
	California	35%	8.84%	40.7%
	West Virginia	35%	8.75%	40.7%
	Delaware	35%	8.7%	40.7%
	Vermont	35%	8.5%	40.5%
	Indiana	35%	8.5%	40.5%
	New Hampshire	35%	8.5%	40.5%
	Maryland	35%	8.25%	40.4%
	Louisiana	35%	8%	40.2%
	Wisconsin	35%	7.9%	40.1%
	Nebraska	35%	7.81%	40.1%
	Idaho	35%	7.6%	39.9%
	New Mexico	35%	7.6%	39.9%
	Connecticut	35%	7.5%	39.9%
	Kansas	35%	7.35%	39.8%
	Illinois	35%	7.3%	39.7%
	New York	35%	7.1%	39.6%
1	**Japan**	**30%**	**11.56%**	**39.54%**
	Arizona	35%	6.968%	39.5%
	North Carolina	35%	6.9%	39.5%
2	**United States**	35%	**6.54%**	39.3%
	Montana	35%	6.75%	39.4%
	Oregon	35%	6.6%	39.3%
	North Dakota	35%	6.5%	39.2%
	Alabama	35%	6.5%	39.2%
	Arkansas	35%	6.5%	39.2%
	Tennessee	35%	6.5%	39.2%
	*Washington	35%	6.4%	39.2%
	Hawaii	35%	6.4%	39.2%
	Missouri	35%	6.25%	39.1%
	*Michigan	35%	6.04%	38.9%
	Georgia	35%	6%	38.9%
	Kentucky	35%	6%	38.9%
	Oklahoma	35%	6%	38.9%
	Virginia	35%	6%	38.9%
	Florida	35%	5.5%	38.6%
	Mississippi	35%	5%	38.3%
	South Carolina	35%	5%	38.3%
	Utah	35%	5%	38.3%
	Colorado	35%	4.63%	38.0%
	Ohio	35%	3.4%	37.2%
	*Texas	35%	1%	35.7%
	Nevada	35%	0%	35.0%
	South Dakota	35%	0%	35.0%
	Wyoming	35%	0%	35.0%
3	**France**	**34.43%**		**34.4%**
4	**Belgium**	**33.99%**		**33.99%**
5	**Canada**	**19.5%**	**14%**	**33.5%**
6	**Luxembourg**	**22.88%**	**7.5%**	**30.38%**
7	**Germany**	**15.83%**	**14.4%**	**30.18%**
8	**New Zealand**	**30%**		**30%**
9	**Spain**	**30%**		**30%**
10	**Australia**	**30%**		**30%**
11	**United Kingdom**	**28%**		**28%**
12	**Mexico**	**28%**		**28%**
13	**Norway**	**28%**		**28%**
14	**Sweden**	**28%**		**28%**
15	**Italy**	**27.5%**		**27.5%**
16	**Korea**	**25%**	**2.5%**	**27.5%**
17	**Portugal**	**25%**	**1.5%**	**26.5%**
18	**Finland**	**26%**		**26%**
19	**Netherlands**	**25.5%**		**25.5%**
20	**Austria**	**25%**		**25%**
21	**Denmark**	**25%**		**25%**
22	**Greece**	**25%**		**25%**
23	**Switzerland**	**8.50%**	**14.47%**	**21.17%**
24	**Czech Republic**	**21%**		**21%**
25	**Hungary**	**20%**		**20%**
26	**Turkey**	**20%**		**20%**
27	**Poland**	**19%**		**19%**
28	**Slovak Republic**	**19%**		**19%**
29	**Iceland**	**15%**		**15%**
30	**Ireland**	**12.5%**		**12.5%**

Source: http://www.oecd.org/dataoecd/26/56/33717459.xls, CCH, Tax Foundation

Figure 2.2.15 Corporate taxes of U.S. states and OECD countries ranked.

The * in Figure 2.2.15 refers to the following explanations: For the purposes of comparability, Washington's B&O gross receipts tax has been converted into an effective CIT rate and Texas'

1% margins tax rate has been included as if it were a traditional CIT. Ohio's CIT is phasing out, but the new CAT (commercial activity tax) is not reflected here. In short, as explained in the text, these three states really have business activity taxes that tax on a basis very different from income.

Source of U.S. 2008 CIT information (Figure 2.2.15) is the following website:
http://www.taxfoundation.org/taxdata/show/23034.html

Source of OECD 2008 income tax data (Figure 2.2.15) is the following website:
http://www.oecd.org/dataoecd/26/56/33717459.xls

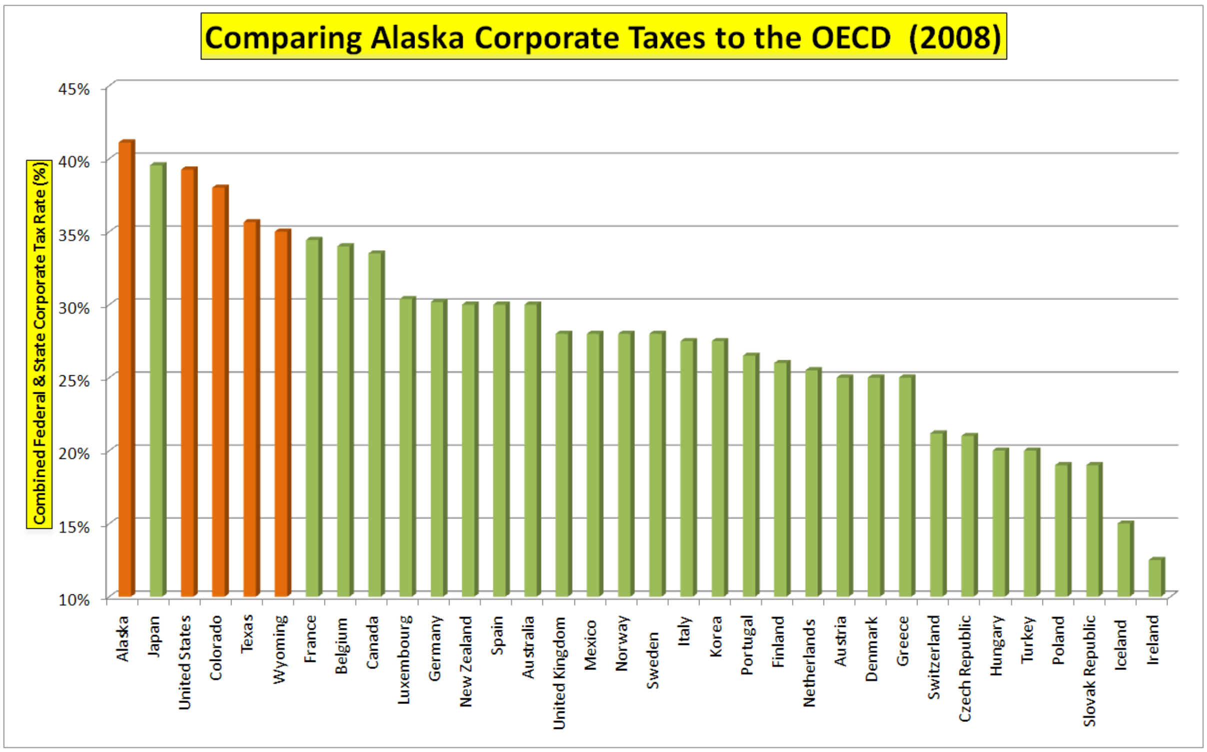

Figure 2.2.16 Corporate taxes in Alaska and selected US states and OECD countries ranked.

This ranking is undoubtedly an over-simplification of the combined tax comparison between states and nations, but it is a comparison that is likely to be used by some potential investors (both domestic and foreign) and analysts in making judgments concerning the fiscal burden imposed by Alaska relative to other U.S. states. It is a mistake to take such comparisons at face value because the base on which the tax rate is applied varies significantly from state to state.

Figure 2.2.17 illustrates the diverse methods used by individual U.S. states to calculate tax bases for corporate income tax.

STATE APPORTIONMENT OF CORPORATE INCOME

(Formulas for tax year 2008 -- as of January 1, 2008)

ALABAMA *	3 Factor	NEBRASKA	Sales
ALASKA *	3 Factor	NEVADA	No State Income Tax
ARIZONA * (2)	75% Sales, 15% Property & Payroll	NEW HAMPSHIRE	Double wtd. Sales
		NEW JERSEY (1)	Double wtd. Sales
ARKANSAS *	Double wtd. sales	NEW MEXICO *	Double wtd. sales/3 Factor
CALIFORNIA *	Double wtd. sales	NEW YORK (3)	Sales
COLORADO *	3 Factor/Sales & Property	NORTH CAROLINA *	Double wtd. Sales
CONNECTICUT	Double wtd. sales/Sales	NORTH DAKOTA *	3 Factor
DELAWARE	3 Factor	OHIO *	60% Sales, 20% Property & Payroll
FLORIDA	Double wtd. sales		
GEORGIA	Sales	OKLAHOMA	3 Factor
HAWAII *	3 Factor	OREGON *	Sales
IDAHO *	Double wtd. sales	PENNSYLVANIA *	70% Sales, 15% Property & Payroll
ILLINOIS *	Sales		
INDIANA (3)	70% Sales, 15% Property & Payroll	RHODE ISLAND	3 Factor
		SOUTH CAROLINA (4)	Double wtd. sales/Sales
IOWA	Sales	SOUTH DAKOTA	No State Income Tax
KANSAS *	3 Factor	TENNESSEE *	Double wtd. Sales
KENTUCKY *	Double wtd. sales	TEXAS	Sales
LOUISIANA	Sales	UTAH *	3 Factor/Double wtd. sales
MAINE *	Sales	VERMONT	Double wtd. Sales
MARYLAND	Double wtd. sales/Sales	VIRGINIA	Double wtd. Sales
MASSACHUSETTS	Double wtd. sales	WASHINGTON	No State Income Tax
MICHIGAN	Sales	WEST VIRGINIA *	Double wtd. Sales
MINNESOTA (3)	81% Sales,9.5% Property & Payroll	WISCONSIN *	Sales
		WYOMING	No State Income Tax
MISSISSIPPI	Accounting/3 Factor	DIST. OF COLUMBIAA	3 Factor
MISSOURI *	3 Factor/sales		
MONTANA *	3 Factor		

Source: Compiled by FTA from various sources.
Note: The formulas listed are for general manufacturing businesses. Some industries have special formulas different than those reported. A slash separating two formulas indicate taxpayer option.

* State has adopted substantial portions of the UDITPA.
(1) A 3-factor formula is used for corporations not subject to the corporation business franchise tax.
(2) Corporations using this formula must release financial data to the Legislative Budget Committee, otherwise use double weighted sales.
(3) State is phasing in a single sales factor. Weightings will change each year until 100% sales factor in 2011 for Indiana, and 2013 for Minnesota.
(4) Taxpayers are allowed only 40% of the reduced taxes from a single sales factor (60% in 2009).

Figure 2.2.17 Corporate income tax base components for U.S. states.

Note that Figure 2.2.17 suggests more uniformity than actually exists. First, it suggests that the base being apportioned is the same for all states but as indicated above the Texas Margin Tax, the Washington Business & Occupations Tax and the Ohio Commercial Activity Tax are not income taxes.

Also, it lumps Alaska together with many other three-factor states, implying a degree of uniformity that is not appropriate. No state other than Alaska has oil and gas production included among its three apportionment factors, and contrary to many other states Alaska does not include a payroll component in its apportionment factor.

Interestingly, many apportionment states in the Lower 48 have abandoned the classic three-way apportionment weighting approach and are now focused on encouraging employment growth. Consequently such states are increasing the weight of the sales component in their apportionment factor, at the expense of their payroll factors. On the contrary the sales component remains typically the smallest component of the Alaska apportionment factor.