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

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For

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Section 2.5

Key features of the fiscal designs implemented by gas exporting countries

Part 2: Natural Gas Fiscal Design - Clarifications

2.5 Key features of the fiscal designs implemented by gas exporting countries

The objective of this section of the study is to identify the range of fiscal elements and their combination in fiscal designs implemented as part of the fiscal systems of major natural gas producing and exporting countries, or those with potential to become major gas exporters. This requires an analysis of both natural gas and crude oil (C5+) fiscal terms from a number of relevant countries. The crude oil fiscal terms are important as many fiscal designs applied to gas either originated from existing crude oil fiscal designs or are integrated with crude oil into single fiscal designs applied to all upstream production. Alaska current fiscal design includes a progressivity term incorporated in its production tax that integrates revenue streams from oil and gas. In international fiscal designs some fiscal instruments apply to oil and gas combined as barrels of oil equivalent, other have instruments that apply separately to oil and gas revenue streams.

Strategic Issues and Objectives

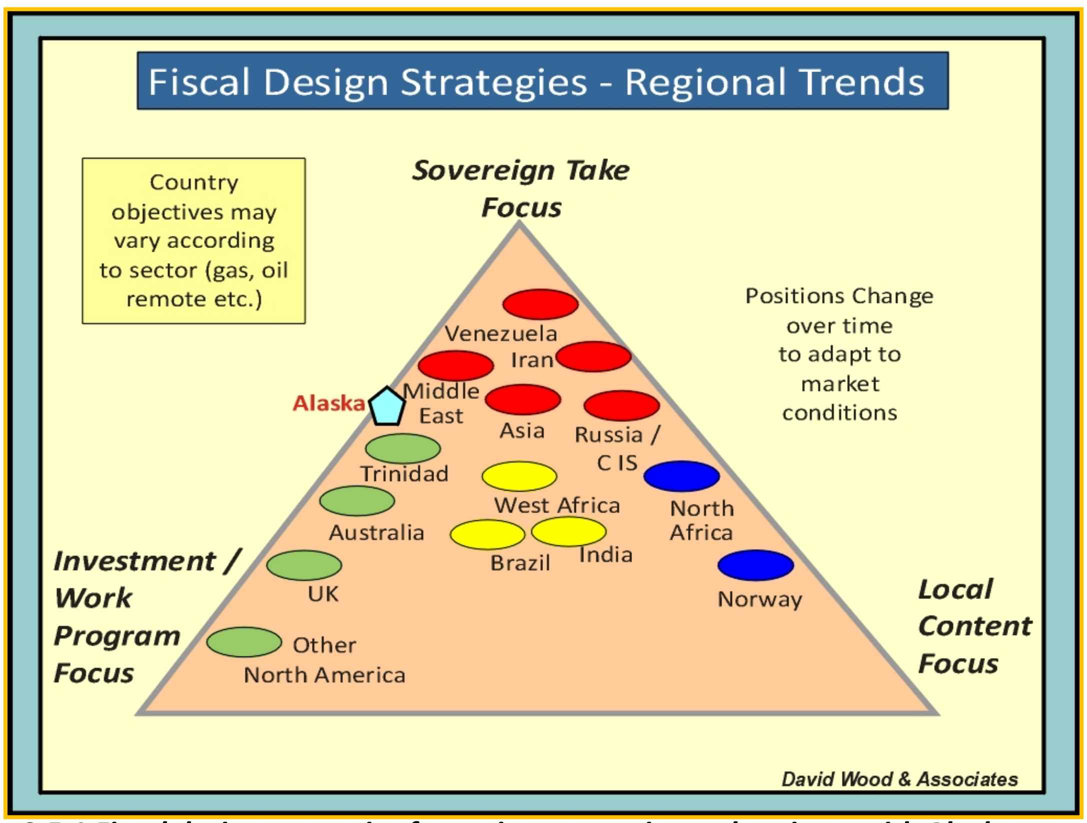

Figure 2.5.1 Fiscal design strategies for various countries and regions, with Alaska highlighted.

Upstream fiscal designs should reflect the broader strategies and objectives that governments are striving to achieve. In this regard it is useful to establish what are those broader strategies and how do they compare with those of other countries before identifying what fiscal designs might be appropriate for specific countries. Figure 2.5.1 identifies the strategic focus of certain countries and regions and the primary strategic objectives that impact their upstream fiscal designs and their selection of fiscal instruments.

In contrast to the rest of North America, Alaska is placed in a position indicating that sovereign take and investment activity dominate its current fiscal design. Maximizing sovereign take formed a key component of the fiscal changes adopted in 2006 and 2007, but these were accompanied by investment credits that also focus upon encouraging investment. Alaska has modified its fiscal design to provide a significantly higher sovereign take than other U.S. states and Canada. However, the recent rounds of fiscal reform have not focused specifically upon stimulating development of the local contribution in terms of jobs, services and suppliers to Alaska's oil and gas industry nor on expanding Alaska's oil and gas service and supply industry and boosting local employment in those sectors.

The three key strategic objectives and drivers considered to influence upstream oil and gas fiscal designs are:

- Maximizing sovereign take
- Maximizing local content
- Maximizing investment and work program

In reality most countries are attempting to balance all three strategic objectives in their upstream fiscal designs and select fiscal instruments that optimize all three. The challenge is that certain fiscal instruments may enhance the achievement of one or other of these objectives but at the expense of one or more of the other strategic objectives. It is for this reason that fiscal designs usually represent a compromise in which certain fiscal instruments work toward different objectives. Segments of public opinion and different government departments may strategically focus on different corners of Figure 2.5.1 within a specific jurisdiction. The dilemma for fiscal designers and those seeking legislative support for amendments to a fiscal design is that it is not possible for a single fiscal design to satisfy all three corners at the same time.

Figure 2.5.1 indicates that many of the more politically extreme developing countries have fiscal designs that are focused on maximizing sovereign take with less regard for incentivizing local content and maximizing work programs and inward investment. The approach in such cases is generally that the latter two objectives should be achieved through contractual obligations and legislative measures rather than fiscal incentives. Local content (employment, indigenous contractors, and skills and technology transfer) is a secondary focus for such countries, but it is more often mandated contractually rather than through fiscal design.

Norway stands out in Figure 2.5.1 because of its strong focus on local content (with secondary focus on sovereign take) in the fiscal design. This is reflected in the high state-equity interest the government takes in all major oil and gas development projects and the predominance of the national oil company (StatoilHydro) in Norway's domestic oil and gas operations. More recent improvements in tax credits have, however, started to place some emphasis on using fiscal incentives to encourage inward investment and exploration.

The strategies of Australia, Canada, U.K. and U.S. contrast with that of Norway in that the focus is very much on encouraging investment and work programs, with almost no fiscal incentives for developing local industries and employment. And, without an NOC, there is no government equity participation in any oil and gas development projects or holdings in strategic infrastructure. The nations' focus is on regulators ensuring a level playing field for all investors to encourage inward investment. Relatively low sovereign takes in the upstream fiscal systems of these countries (except in Alaska) places further emphasis on fiscal strategies focused on encouraging investment by offering a greater share of the economic rent to IOCs prepared to take the required risks. This is deemed necessary because of either diminishing resource bases (e.g. U.K. and conventional oil and gas in Lower 48 U.S.) or high-cost, technologically challenging resource bases (e.g. Alaska and Canada).

Some countries stand out in Figure 2.5.1 as having fiscal designs that do provide a more balanced focus on all three of the strategic objectives considered. Brazil, India and some West Africa countries have evolved fiscal designs that include instruments directed at all three objectives, attempting to optimize upstream oil and gas performance within their respective countries.

It is not a question of whether one approach is better or more desirable than another, but rather that there are strategic options and decisions to make in selecting fiscal designs that may have conflicting impacts on the performance of the upstream sector. It is important when selecting or modifying fiscal design to be aware of the strategic constraints, imposed either politically or by market and environmental forces, that restrict the use of certain fiscal elements in specific circumstances.

Key Fiscal Instruments Employed in the Upstream Sector of Major Gas Producing Countries and those Countries with Potential to become Gas Exporters

The following analysis draws from the more detailed accounts of fiscal design for specific countries presented in Appendix 3 of this study. Readers are directed to that section to review more in-depth accounts of the fiscal designs of the specific countries mentioned here, as there are many interesting combinations of fiscal instruments employed and, in the case of some countries, complex issues and reasons for applying them that are not addressed in this section.

The 23 countries and regions analyzed are listed below and then presented in alphabetical order. Those countries that could compete for $20 billion plus investments in gas developments over the next decade are marked with a star.

Alaska ☆	Algeria ☆
Angola ☆	Australia ☆
Azerbaijan	Bolivia ☆
Brazil ☆	Canada - Alberta ☆
Canada – Other Provinces ☆	Egypt ☆
Indonesia ☆	Libya ☆
Malaysia ☆	Nigeria ☆
Norway ☆	Papua New Guinea ☆
Peru ☆	Philippines
Qatar ☆	Russia – Sakhalin II ☆
Trinidad & Tobago ☆	Tunisia
United Kingdom	USA ☆

What is clear from Appendix 3 of this study is the extreme diversity of fiscal designs and wide range of fiscal instruments applied to the upstream oil and gas industry around the world. This provides a broad spectrum of fiscal instruments, some of which are quite innovative and worthy of close consideration. There is clearly potential to combine some of these instruments to form a new fiscal design or to introduce them into an existing fiscal design to improve its performance with respect to specific objectives. There is much to be learned from the various countries profiled in more detail in Appendix 3 of this study and highlighted below. Some of these fiscal instruments have the potential to improve performance of the existing Alaska fiscal design and will be addressed in that regard in the next section of this study.

There are of course constraints on what amendments could be realistically achieved politically or contractually in Alaska. The vast majority of acreage that would potentially supply gas to an Alaska gas pipeline is already leased out. The ability to amend specific existing lease terms does not exist, as the leases are binding contracts (unlike state statutes, which can be changed with legislature approval). This suggests that amendments in Alaska would need to focus on production taxes and new fiscal incentives rather than amending royalty rates and specific lease provisions. Notwithstanding such limitations there is much scope to build in both incentives and penalties into production tax mechanisms that mitigate (or extend) the impacts of existing fiscal instruments. It is with this constraint in mind that much of the discussion concerning the fiscal designs and specific fiscal instruments of the countries reviewed should be considered.

The following analysis highlights certain features of the upstream fiscal systems applied by the countries mentioned that are relevant to more general considerations of fiscal design. These highlights do not describe the full spectrum of upstream fiscal instruments applied in those countries (see Section 3 for more details).

Countries are addressed here in alphabetical order with no preferential focus on those countries which operate mineral-interest or PSA regimes or political groupings that are more or less politically aligned with U.S. (e.g. OECD countries) or other U.S. states. An alternative approach would be to highlight and focus attention upon those countries and other U.S. states at the expense of developing countries and PSA regimes on the presumption that the latter are significantly less relevant to and unworkable in Alaska. This author does not agree with the alternative approach and believes that there are important lessons for Alaska to learn from all of the countries reviewed here. Indeed some of the key lessons on alternative fiscal elements worthy of consideration, and their advantages and disadvantages, come from developing countries operating PSAs. The alphabetical approach is therefore adopted in these sections with key points relevant to Alaska highlighted in the executive summary and further developed in Sections 2.6 and 2.7.

Algeria

- 51% state controlling interest specified since 2006. Operates several fiscal systems in historic contracts.
- Different amortization rates applied; quicker for frontier areas and longer for established producing areas or highly prospective areas.
- Revenue tax rate is linked to cumulative market value (note <u>value,</u> not profitability) of production. This removes the cost component and issues of IOC "gold plating".
- Income tax is levied on profits at 30% with reduction to 15% if reinvested in Algeria.
- Windfall tax on extraordinary income on scale from 5% to 50% (non-deductible against other taxes) if Brent oil price > US$30/barrel. Scales governed by magnitude of oil price and, in some case, also scales of production.
- National agency (Alnaft) set up including special powers for gas, including rights to monitor and approve terms of gas sales and swap agreements and to specify market gas prices to be used in taxation calculations.
- Farm-out deals are charged a 1% transaction fee.

Angola

- Operates several fiscal systems in historic contracts.
- Uplift of capital costs (50% in old-style mineral-interest agreements and by a factor of 1.4 in PSAs) for cost recovery; negotiable from 10% to 50% in deepwater licences. A cost uplift increases the costs that can be recovered (PSA) as cost oil/gas, or that can be depreciated and offset against taxes (mineral interest). Uplifts are comparable to tax allowances rather than tax credits, i.e. they reduce taxable income.
- State equity participation negotiable (< 20%).

- Price cap is a feature (profits above a certain price go to the government, an extreme windfall tax) of some contracts.
- Very high signature bonuses (highest in the world) for prospective areas agreed in exchange for more lenient fiscal terms (protected by fiscal stability clauses).
- Capital costs ring-fenced to each field, exploration costs to each PSC area.
- Profit oil split on sliding scale linked to post-tax IRR (internal rate of return), rising from 20% to 90% marginal rates to the government for deepwater PSCs. In older PSCs this split was linked to cumulative oil produced (~90% to government once 100 million barrels had been produced). Government sees its share later offshore.
- Natural gas no-flaring rules, but issues of cost in gathering associated gas from deepwater and delivering to onshore LNG facility.
- Competitive bidding rounds used effectively because of very high prospectivity.

Australia

- Operates two distinct systems: 1) a ***volume-based*** royalty system in North West Shelf (NWS), onshore and LNG; and 2) a petroleum resource rent tax (PRRT), a ***profit-based*** system for all discoveries made since 1990.
- PRRT at 40% applies to marketable petroleum commodities, such as stabilised crude oil, condensate, natural gas, liquefied petroleum gas, and ethane.
- A "project" consists of facilities in the project title area, and any facilities outside that area necessary for the production and initial storage.
- Cost uplift at rates above long-term bond rate: 15% above for exploration; 5% above for other costs.
- In the royalty licences an exemption for condensate was removed in 2008; industry complained about lack of consultation before change was introduced.
- Terms and issues highlight for gas projects the importance of definition of tax treatment of different liquid types and inclusion/exclusion of field-based facilities and processing and storage facilities along the supply chain.

Azerbaijan

- Fiscal system involves a production-sharing contract (PSC) system.
- Cost oil/gas allocation is 100% for operating costs, but negotiable (50%+) for capital costs. This is the percentage of the revenue stream in any period which is made available for recovery of costs. Profit oil/gas is split in some contracts according to a sliding scale based on an R-factor with government share rising from 50% to 90% (R>3.5).
- In other contracts profit oil/gas is split according to a sliding scale based on real after-tax IRR with government share rising from 20% (IRR < 16.75%) to 75% (IRR>24.75%).
- State Oil Company of Azerbaijan Republic (SOCAR), the NOC, participates with up to a 20% equity share in most projects on a fully-paid (not carried) basis.
- Income tax is on a sliding scale based upon rate of return, typically varying between 10% and 35%.

- The upper income tax rate also depends on the working interest held by an IOC. For working interests above 30% the tax rate is 30%. This is a way of directing taxes at larger companies (rules needed to exclude multiple affiliates).
- For working interests less than 30% the income tax rate is 25%, increasing to 35% at higher profit levels. In remote mountainous areas onshore tax rate is 10%.
- Profits reinvested in Azerbaijan are exempt from income tax. Azerbaijan is unusual in the 100% exemption, although many countries offer partial exemptions.

Bolivia

- Bolivia has had significant exploration success and increased its natural gas reserves by 10-fold with the aid of exploration investment from IOCs in past 15 years.
- Community unrest and a populace which perceived itself as disenfranchised from potential wealth created from oil and gas revenues resulted in revolution in 2003.
- Regime now closely aligned with Chavez's Venezuela.
- Nationalization of key industry assets and reserves has followed since 2005 and a new hydrocarbon law reinstated the NOC YPFB (previously sold off in the 1990s).
- Combined tax and royalty rate of 50% (up from 18%) applied to all the oil and gas production.
- An additional tax/royalty of 32% applied to large fields/high production rates.
- Further appropriations (i.e. partial or full nationalisations) in 2008 (e.g. Ashmore's 50%-stake in Transredes gas export pipeline).
- RepsolYPF, BP, BG, Total and Petrobras are the IOCs most affected by appropriations. Arbitration cases have followed in some cases for compensation.
- Chance of securing investment or long-term gas sales agreements needed to develop gas export projects is now very low. IOCs holding on to their reserves have little chance of achieving returns on investments over the medium term; the consequences of fiscal instability and high political risk.

Brazil

- Not a natural gas exporter, but significant producer with active and successful upstream exploration programs involving IOCs.
- Petrobras state monopoly removed in 1997. Agencia Nacional do Petroleo set up by government to regulate the industry and several successful upstream licensing rounds have followed.
- Mineral-interest fiscal system: royalty, special participation tax (SPT) and a raft of quite complex local and corporate taxes.
- Royalty at 10%. Reduced rates considered for marginal fields. 1% additional royalty onshore for local land owners.
- SPT is applied only to large production volumes or great profitability and rises in tranches triggered by specified daily production rates to a maximum marginal rate of 40%. For a field producing 100,000 barrels per day in 500m of water depth the effective average SPT rate in 2008 is some 11.5%.

- Government declared intention in 2008 to increase SPT rates in light of high prices and giant field discoveries since 2007.
- Ring-fences are around the country for most taxes, but are around each field for SPT.
- Import duties applied and VAT exemptions not upheld in certain regions.

Canada

- Canada is a potential transit route and customer for some of the natural gas shipped from Alaska and at the same time a competitor in producing as yet undeveloped gas reserves from its Arctic sedimentary basins. Its fiscal designs are therefore of great relevance to Alaska.
- Royalty is the key fiscal element imposed in Canada. However, royalty mechanisms vary significantly from province to province. Royalties generally involve quite complex calculations but achieve highly flexible and progressive fiscal systems.
- In Alberta, which tightened its fiscal terms significantly in October 2007 (new terms to commence in 2009), there are three different royalty structures: crude oil, natural gas and oil sands. For natural gas royalty rates are on sliding scales from 5% to 50%, calculated by formulas involving production rate, gas price and depth to reservoir.
- Royalty credits act as incentives for ultra-deep drilling, enhanced oil recovery (EOR) projects including those using CO_2 as an injectant, and new technology development projects.
- In several other Canadian provinces a progressive component of royalty is driven by rates of return set up in tiers (e.g. NWT, Newfoundland and Nova Scotia).
- For the Hibernia field basic royalty is increased incrementally after each 18 month period of production or when cumulative production thresholds have been reached. During government loan repayment periods if oil prices fall below a threshold price royalty rates are reduced according to indices.
- Provincial CIT rates vary between 10 % in Alberta and up to 17 % elsewhere, so combined federal/provincial CIT rates for 2006 ranged from 32.12% to 39.12%.
- Provincial (state) tax is not deductible against the federal tax.

Egypt

- Concessions granted to the NOC (Egyptian General Petroleum Corporation, EGPC) and PSCs to IOCs.
- PSC fiscal system is regressive with a raft of signature and production bonuses, a royalty (10%) and profit oil shares split on sliding scales (negotiable) linked to daily production rates and rising to marginal rates of 85% to the government.
- Cost oil and gas limits are close to 50% and sometimes higher for gas.
- Contract period is 20 years from the date of commercial discovery, with a 5-year extension subject to Egyptian Natural Gas Holding Company (EGAS) approval and a competitive bonus payment.

- Farm-out agreements are taxed with an assignment bonus of not less than 10% of the value of the deed of assignment. EGAS has pre-emption rights.
- Domestic gas prices linked to a formula of Brent oil prices providing a floor price US$1.5/mmbtu when Brent oil <= US$10/barrel, rising to a maximum of US$2.65/mmbtu when Brent oil >US$22/barrel. Floor price helps ensure basic project profitability. Domestic market has priority over exports.
- Fiscal stability is guaranteed in the contract. Income tax paid on behalf of contractor by EGPC.

Indonesia

- PSCs have been applied since 1960s. Now administered by BPMigas (a government ministry) rather than the NOC (Pertamina).
- Contract term is for 30 years to conduct exploration, development and production activities; extendable up to 20 more years. Special durations can be negotiated for gas. Signature and production bonuses (~US$1 million) applied.
- Ring-fences apply to each contract and revenues and cost within its area.
- First-tranche petroleum (FTP) allocation of ~15% to 20% (negotiable) split between IOC and government, regardless of profitability (it is like a royalty, but it is split between the parties) to guarantee the government a minimum revenue stream. FTP acts as a cost recovery limit of 80%.
- Profit is split on an 80:20 basis (government:IOC) after tax for oil and 70:30 basis for gas in recent contracts. Historically the terms were more favourable to the government as a post-tax profit split of 85:15 was applied. IOCs pay the income tax and the effective tax rate (inclusive of all taxes) is specified and fixed in the contract.
- Investment credit of 17% available for new field developments and for enhanced oil recovery (EOR) and incremental oil recovery (IOR) projects.
- Verifying and auditing costs is bureaucratic and government believes IOCs try to abuse cost-recovery system.
- Minimum equity participation by Indonesian companies in post-2003 PSCs is 10%. Offered first to local companies and then to Pertamina on a heads-up basis.
- Domestic market obligation (DMO) of about 25% (negotiable) of IOC production share sold to domestic market at 15% to 25% (negotiable) of market price. Huge fiscal burden on IOCs.

Libya

- International sanctions lifted in 2004; changes in fiscal terms (under EPSA IV, the fourth design for exploration and production-sharing agreements) have led to massive increase in investment in exploration, development and gas infrastructure.
- High-profile license rounds with government share of profits (M-factor) the main biddable item, accompanied by a bid bonus. M-factors bid range from 60% to 90%.

- NOC is carried through exploration costs, pays 50% of capital costs and 65% of operating costs. IOC cost-recovery allocations are 100% for exploration costs, 50% for development costs and 35% for production costs.
- The IOC share of profits under EPSA IV terms used an R-factor adjustment on a fixed sliding scale of 0.9 up to R of 1.5; 0.7 for R between 1.5 and 3; and 0.5 for R greater than 3. Under earlier EPSA terms the government share of profits was fixed at 65% but a further adjustment of IOC share by production volumes and R-factor applied.
- The most aggressive bids by IOCs (U.S. majors) since 2005 have resulted in terms that provide the government with more than 95% share of profits (e.g. Occidental and Hess).
- On declaration of commerciality, operatorship is transferred from the IOC to a company jointly owned by the foreign contractor and NOC.
- EPSA IV includes a comprehensive gas clause that provides that natural gas discovered and produced by IOCs will be marketed jointly with NOC. Domestic gas sales are indexed to international fuel prices.
- In gas area bidding round of December 2007 Shell won two Sirte basin blocks (with a bid of M-factor 85% and $93 million signature bonus), with 90%+ profits to government.
- Many major IOCs are making commitments to build gas and LNG infrastructure on very harsh fiscal terms and in spite of high political uncertainties.

Malaysia

Specifies a fiscal design philosophy. The government emphasizes 5 key objectives –

1. Ensure fair return/rewards to successful investors based on prospectivity and level of risk taken.
2. Allow recovery of all cost in exploration and development upon success
3. Encourage reinvestment to sustain production profile of discovered fields.
4. Adopt partnership approach in dealing with foreign investors.
5. Create conducive work environment to facilitate business activities.

- It operates a production-sharing system. In the late 1980s fiscal take was amongst the toughest in the world with >90% of profits going to the government.
- Since 1990s have eased terms to include sliding scales linked to an R-factor (cumulative revenue/cumulative cost or R/C Index) noting that R/C of 1 is payback on an undiscounted basis, but R/C of ~1.4 is payback on a discounted basis.
- Both cost oil/gas and profit splits are linked to R-factor at the field, not at the contract level.
- Innovative method for linking cost oil allowances and unused cost oil splits to R-factor encourages IOCs not to “gold-plate” costs, because IOCs get higher splits of unused cost oil than profit oil for any given R-factor (see Part 3 for details).
- Contract term is 29 years consisting of: 5 years exploration (with 5 years grace for the IOC to hold on to gas discoveries prior to declaring them commercial); 4 years development; 20 years production. For the deepwater terms the total period is 38 years

consisting of: 7 years exploration (with 5 years grace for the IOC to hold on to gas discoveries prior to declaring them commercial); 6 years development; 25 years production.

- Enhanced cost recovery and profit splits applied to two deepwater zones based upon water depths of 200 metres to 1,000 metres and greater than 1000 metres.
- Government participation (15% to 25%) mandatory. High priority given to developing local skills and industry participation.
- Royalty and taxes quite harsh, with an export tax applied to remittances
- Price cap applied for windfall profits (excess value) tax of 75% of all profits above a specified oil price (inflated in line with cost indices).

Nigeria

- Multiple fiscal systems operated with significant flexibility of designs and incentives applied over many decades.
- For many years the government applied a harsh fiscal take in mineral-interest onshore concessions (joint-venture areas), but with a guaranteed minimum return to IOCs in low oil price environments and with incentives for reserves additions and maintaining costs within certain limits on production unit basis (i.e. US$/barrel). See Part 3 for details.
- Negotiated alternative funding schemes (e.g. tax suspensions until costs recovered) for joint-venture (JV) projects in order to get NOC (Nigerian National Petroleum Corporation, NNPC) costs paid upfront in major development. NNPC generally holds 60% equity position in JVs.
- PSCs now applied offshore and initially for deepwater; traded off less harsh fiscal terms in exchange for high (US$100s million) signature bonuses. PSC terms have been progressively tightened since large reserves have been found, with NNPC taking equity interests typically up to 20%.
- 2005 deepwater terms: royalty rate still reduced by water depth; cost oil allocation limited to 80% or less.
- Cost carry for local companies (<10%) recoverable from profit oil.
- Investment tax allowance of 50% (1993 to 1998 this was a tax credit).
- Profit oil/gas split historically on sliding scale linked to cumulative production (hits big IOCs/projects harder); since 2005 some contracts linked to R-factor (i.e. profitability) with 70% to IOC up to R-factor of 1.2, decreasing to 25% to IOC for R-factor above 2.5.
- Special reduced terms and tax holidays for indigenous companies and marginal fields.
- Lacks stable fiscal terms for gas with no domestic market or established gas pricing mechanism. Nevertheless it has become world's fifth largest LNG exporter without such terms, due to long-term, take-or-pay contracts indexed to international prices.
- Facing challenges to introduction of no-flaring rules in 2008 and securing investment commitments without clear fiscal terms/commercial pricing for gas.
- Some expecting up to a 25% gas supply domestic market obligation at highly discounted prices to be introduced and applied to future gas export projects.

- Government reform of ministry and state-owned entities under way; NNPC to be replaced by the renamed and restructured NAPCON and empowered to set up incorporated joint ventures where new companies with a separate board are established on each project; National Petroleum Directorate will replace Department of Petroleum Resources.

Norway

- Government's portion of the total reserves on the Norwegian shelf in 2005 amounted to some 24% of the oil reserves and 41.6% of the natural gas reserves. This is in addition to StatoilHydro's holdings.
- Mineral-interest fiscal system with two taxes: corporation tax 28%; and a special tax at 50%.
- Uplift of development capital costs (30% spread over 4 years) deductible against special tax means that projects with less than about 15% rate of return are sheltered from special tax.
- Only ring-fence is at company level.
- Uses its Norm Price Board, which comprises four independent members, one member from the Ministry of Petroleum and Energy and one from the Ministry of Finance, to establish market prices and to avoid price manipulation by IOCs. Board meets quarterly to fix monthly norm prices (free market prices) for the previous quarter for each crude oil produced.
- To deduct all net financial costs from tax bases, a company must have an equity-to-assets ratio of at least 20 %. This avoids IOCs exploiting thin capitalized corporate vehicles to exploit loan interest tax deductions.
- In the case of assignments of interests in licences the Ministry of Finance may make adjustments to the tax positions of one or both companies involved to ensure tax neutrality.
- CO_2 tax: Burning of oil, diesel and gas – this applies mainly to power production and flaring on installations in the oil and gas industry -- is subject to a CO_2 tax. The fee is currently NOK 0.79 per Sm3 gas or per litre of oil. [1US$ was approximately 6.6NOK 15 October 2008]. Note that a number of Western European countries have implemented taxes based on the carbon or energy content of a wide range of wholesale and retail energy products (e.g. Sweden, Norway, The Netherlands, Denmark, Finland, Austria, Germany and Italy).
- Norway does not offer tax stability but it makes very strong and persuasive statements that persuade many IOCs of the government's commitment to maintaining profitability for companies willing to invest in the Norwegian Continental Shelf. The government's stance on fiscal stability is quite clear and can be summarized as:

The Norwegian government wishes to portray the tax system as a "sleeping partner" allowing IOCs to take a high participating interest, achieve technical control of projects and *take part in large investment projects. The fiscal design philosophy is for the government take system to be neutral on company decisions, whether those decisions relate to capital investments, operating costs and activities or field shut-down and decommissioning. The government's aim is that a decision that is economically viable before tax should remain so after tax and vice versa. The Norwegian government and the Norwegian Petroleum Directorate (NPD) do not state that taxation rates may not change in the future, but rather emphasize that assets will not be appropriated and projects not rendered uneconomic by fiscal changes and that the state maintains a strategy of projects being profitable for both Norway and the IOCs.*

As recent events have shown, PSCs with fiscal stability clauses can be manipulated by persistent government pressure to increase the government's fiscal take. Norway takes the view that a clear statement of fiscal design strategy and intent is worth more than guaranteeing fiscal stability in the long term. Despite best intentions of fiscal stability clauses, what appears to really count from Norway's perspective is a clear fiscal strategy, a statement of that strategy, consistent actions that promote project commerciality and lead to it being considered as fiscally responsible and credible in the eyes of its nationals and IOC investors. The detail included here concerning Norway's stance on fiscal strategy and stability is provided because it is considered relevant to Alaska potential aspirations in this regard.

Papua New Guinea (PNG)

- This developing nation is remote from natural gas markets and has more potential gas reserves than oil reserves, but in remote and technologically challenging environments. PNG has been striving to secure IOC investment in natural gas export projects for more than 20 years. There are some parallels with the Alaska circumstances with respect to natural gas.
- Gas pipeline projects for Australia have been stalled for many years. In 2008 an ExxonMobil-led group have made commitments to an 18-month, US$400 million front-end engineering design study of $15 billion LNG project. Two other potential LNG projects are also at advanced planning stages. It seems in 2008 that LNG will be the key to opening up PNG gas exports and more than double PNG's GDP.
- PNG operates a mineral-interest fiscal system which it has relaxed over the past decade or so to encourage exploration investment and gas export projects. It modified its system further in 2008 to secure commitment from the ExxonMobil-led group to progress their LNG project.
- The integrated LNG projects (upstream gas field development plus pipeline plus liquefaction facilities) will pay income tax of 30% (reduced from 50% a few years ago) plus additional profits tax (APT) linked to a projects post-tax internal rate of return (IRR).
- APT rate is 7.5% when the project's IRR exceeds 17.5% and APT rate increases to a rate of 17.5% when IRR exceeds 20%. APT in 2008 is at a lower rate than it would have been in the 1990s (50% rate when IRR exceeded 27%) or in 2003 (20% APT when IRR

exceeded 15%; second-tier 25% APT when IRR exceeded 20%). PNG government has shown that it is prepared to relax fiscal terms for frontier and costly projects.
- State equity participation is up to 22.5% in any petroleum development project with 2% of that going to landowners. Pre-2002, Orogen Minerals Limited, a public listed company 51% owned by the state, had the option to acquire up to 20.5% interest in all petroleum projects in PNG out of the state's 22.5% entitlement.
- Debt-to-equity ratio is limited to a maximum of 3:1 in development projects.
- Capital expenditure is depreciated over 10 years on a straight-line basis.

Peru
- Licences or service contracts awarded to IOCs under a mineral-interest system.
- IOC free to export oil and gas (or revenues from it) unencumbered by export taxes.
- IOC's share determined at its option by R-factor-driven royalty calculated on a cash basis.
- After 2003 fiscal changes, IOCs have the choice at declaration of commerciality between two royalty calculation options. Once selected there is no opportunity to change method later.
- First royalty option is on a sliding scale linked to production; 5% for less than 5,000 boe/day, up to 20% for production >100,000 boe/day.
- Second royalty option is on a sliding scale linked to the R-factor; minimum of 5% then when R-factor is greater than 1.15 (i.e. 15% nominal return on investment), plus a sliding-scale variable component to royalty up to a total maximum of 20%. The maximum fixed plus variable component is 25%.
- The second option is better for high capital cost projects as it provides them with faster payback and higher rates of return on initial investment. Capital cost overruns would be penalised more in case of first option.
- Profits subject to 30% income tax.
- A major gas liquefaction project involving RepsolYPF, Hunt Oil (Dallas) and South Korean companies is under construction on Peru's Pacific coast. That LNG is destined for the west coast of Mexico, and ultimately the U.S. West Coast. Peru LNG would be a competitor if an Alaska LNG export project materializes in the future.

Philippines
- Not a major gas producer, but has potential in deepwater around Palawan and Sulu Sea areas attracting attention from major IOCs (e.g. ExxonMobil farm-in deal in June 2008 for Block SC56 with local partner Mitra Energy).
- Upstream fiscal contract is generous to IOCs in terms of percentage take but involves a service-type agreement, which has potential reserves booking limitations with U.S. Securities and Exchange Commission.
- Offers fiscal enhancements for deepwater areas: faster depreciation of capital (5 years instead of 10 years); more generous ring-fence allowing unsuccessful exploration costs to be offset against production revenues from anywhere in Philippines.

- Loan interest cost recovery limited to two-thirds of loan interest paid.
- Simple fiscal elements: no royalty; production split 60% to government and 40% to IOC; cost-recovery allocation up to 70% of revenues; IOC taxes paid from government share.
- There is an innovative “negative royalty” incentive, the Filipino Participation Incentive Allowance (FPIA). When local companies (registered in Philippines with Filipino shareholders) participate in the service contracts with equity interests of at least 15% offshore and at least 30% onshore, the contractors (IOCs plus local companies) are eligible to receive the FPIA. The maximum level of the FPIA is 7.5% of the gross revenues. It involves an actual payment to producers (i.e. it is not a royalty relief or reduction in royalty owed), which encourages local industry participation and it is only paid after production is achieved.
- There is no government equity participation. There are modest signature and production bonuses and annual training funds.

Qatar

- In little more than a decade from mid-1990s Qatar transformed itself from no gas exports to the world’s largest LNG exporter, by a number of joint venture projects with major IOCs (Mobil and subsequently ExxonMobil, Total and Japanese gas customers).
- State interest in all midstream projects is high (65% to 70%) and held by Qatar Petroleum (QP).
- Several other major IOCs (e.g. Shell, ConocoPhillips) investing billions of dollars in gas monetization projects (LNG, GTL and petrochemicals).
- Fiscal terms are harsh from IOC perspective, but offer involvement in integrated upstream and midstream projects, guaranteeing revenue streams from along the entire natural gas supply chain.
- Upstream component governed by shallow-water, production-sharing agreement (PSA) with about 50% cost oil/gas recovery allocation and a modest feed gas price (about US$0.5 to US$1.5/mcf) paid for gas supplied to the midstream gas processing (LNG, GTL etc.) facility operated as a joint venture with QP.
- Production sharing for upstream gas is on a sliding scale linked to production volumes (about 65% to QP for production <130 mmcf/day up to about 90% to QP for production >520 mmcf/day).
- Oil, condensate (C5+), heavy NGLs and light NGLs from the offshore production provide key revenue streams for the IOCs. These are split under the PSC according to an R-factor, i.e. profitability (about 65% to QP for R-factor <1.0, and up to about 90% to QP for R-factor >2.5). This is quite a harsh scale, but provides IOCs with more of the total revenue stream in the early years and significantly accelerates cost recovery of the whole project (upstream and downstream) from the IOC’s perspective.
- All upstream taxes are paid from QP’s share on behalf of IOCs.

Russia Sakhalin II

- This project has a unique (both in Russian and global sense) fiscal structure and has become high profile in the context of fiscal stability as the Russian government has managed to engineer itself into a 51% controlling position at a discounted cost after the IOCs (Shell and Japanese partners) had taken the risk and invested most of the capital. Massive cost overruns and environmental issues combined with the PSC fiscal structure had weakened IOCs negotiating position with the government.
- PSC has a 100% cost-recovery allowance and fast capital depreciation schedule highly favourable to IOC with a rate-of-return driver to profit sharing. This turned out to be too good to be true from IOCs' perspective.
- Government only starts receiving its share of revenues once IOCs have recovered both their costs and a 17.5% real rate of return (RROR).
- Once the 17.5% RROR threshold has been achieved the government then receives 10% of the revenues for two years, and then 50% until the IOC has achieved a 24% real rate of return. Once that second threshold has been achieved the government's share of profits increases to the marginal rate of 70%. See Part 3 of this study for detailed calculations of this RROR mechanism.
- At high oil and gas prices and originally budgeted costs the government take would have risen to 70% quite rapidly. At 200% capital cost overrun this happens much later in the production cycle.
- In addition to the RROR profit-split drivers the IOC also pays the government through other fiscal elements: bonuses (>$50 million); repayment of sunken exploration costs from Soviet era (>US$150 million); an 8% royalty, profit tax, and contributions to the Sakhalin Development Fund. The adverse impact on government fiscal revenues from the project caused by the RROR profit split limitations is to some extent mitigated by these other fiscal elements paid by the IOC.
- The duration or term of the Sakhalin II PSA is effectively indeterminate as long as investment continues. The initial phase is set at 25 years, but with the proviso that should IOC consider further exploitation of the fields to be "economically practicable" it can renew the contract without any changes in the PSA terms, for a further five years, followed by a further five years ad infinitum.

Trinidad & Tobago (T&T)

- 58.5% of the LNG imported into the U.S. in 2007 came from Trinidad, making it of huge strategic significance to the U.S. for international gas imports in the futures. With exports to 12 countries it is also the second most diversified LNG exporter worldwide (after Algeria) and 7th largest by total volumes.
- Major challenge for T&T is to prove up more gas reserves. Its gas reserves/production (R/P) ratio was only some 12 years in 2007. Therefore, it is important to incentivize industry to increase exploration investment offshore.

- Applies both historic mineral-interest system and a production-sharing system applied to most contracts issued in past two decades.
- Royalty rate is 12.5% in mineral-interest licenses, but a reduced system applies onshore to encourage smaller-scale onshore projects. Pre-2005 the royalty for gas was fixed at US$ 0.02 per million btu (mmbtu) in licences not due to expire until 2017. BP (main company holding gas reserves and production from Amoco's original licences operated from 1970s to 1990s) was pressured by government to increase this royalty in 2005. BP agreed to a volume equivalent to 10% of gas sold for LNG to pay such a royalty. This royalty has been gradually implemented in a phased manner beginning in 2005 and in 2008 is fully effective. This action (like Sakhalin II for Shell) illustrates how apparent guarantees of fiscal stability are hard to sustain when terms are too favourable to an IOC in current circumstances.
- In addition to royalty, the licences are subject to a petroleum profits tax (PPT) at 50% of net income; an unemployment levy at 5% of net income; and a "green fund" levy at 0.1% of gross income. A supplemental petroleum tax (SPT) is levied on gross income less deductions derived from liquids production, and progressively increases from 0% (oil prices < about US$15/barrel) to about 35% (oil prices above US$49.5/barrel). It is a progressive tax but it is not linked to project profitability. Since 2005 cost deductions from SPT are removed (only the royalty is deducted from tax base), and SPT rates are reduced slightly and calculated on a quarterly weighted-average oil price.
- For PPT there is no ring-fence and unsuccessful exploration costs may be offset against income from any producing operation. For SPT there are separate ring-fences offshore and onshore.
- PSC have production period of 25 years and maximum cost-recovery allocation of around 40% and fiscal stability clause exempting IOCs from taxation on profits. Ring-fences are around each contract area. Profit sharing is linked to sliding scales based on daily production volumes and prices.
- PSC production sharing involves separate scales specified in the contract for oil and gas. Government share progressively increases from 55% to 95%. The price thresholds are quite low (maximum band typically applies at >$2/mmbtu and >US$40/barrel), but at low production rates (for example, <25,000 bopd and < 150 mmcfd) the highest government share is limited to 35%.
- A special corporate income tax applies to midstream projects (35% compared to 25% standard rate).
- Withholding tax applied at 5% to 15% rate on remittances depending on terms of tax treaties with country destination of remittances.
- Heavy-oil capital uplift allowance of 150% (oil <=18 degrees API). 150% of the project costs may be claimed, spread over six years, with 60% allowed in the first year, and 18% annually over the remaining five years. Such a mechanism could be applicable for high-H_2S or high-CO_2 natural gas development projects in Alaska.

Tunisia

- One of the first countries to embrace the R-factor approach in mineral-interest licences and has linked royalties and income taxes to profitability since the 1980s on separate sliding scales for oil and gas (lower rates applied to gas projects). Royalties rise to 15% in most profitable projects. Income tax rises in most profitable projects to 75% for oil and 65% for gas, but reduced rates are applied at all levels of profitability if ETAP (NOC) participates in projects with >40% share.
- In 1999 introduced fiscal revisions, softening terms to stimulate exploration.
- Domestic market obligation is applied to field oil production; 20% of field oil production is sold to the domestic market at 90% of realized oil price (i.e., 10% discount to international prices).
- Government equity participation is negotiable up to about 50% and is at the NOC's option once commerciality is declared by IOC. This fiscal element has the most impact on IOC revenue and profit streams and significantly limits their potential upside. In large fields it is fair to assume that ETAP (NOC) will elect to exercise its option to participate up to a high-percentage equity interest. In small/marginal fields may elect not to participate or participate at a low interest. In early licences the government had an option to back-in up to 55% following a discovery.
- Exploration and development costs may qualify for uplift ranging from 10% - 30% (negotiable). Losses can only be carried forward for up to three years.
- The gas price for local market sales is fixed by decree. In 2000 the gas price was indexed to 80% of the value of Mediterranean low-sulphur fuel oil (LSFO).
- The ring-fence for exploration costs is the whole of Tunisia, meaning that unsuccessful exploration costs in one license could be offset against revenue from a discovery in another license.

United Kingdom (U.K.)

- Since 1993 it has offered one of the most generous fiscal systems to the oil and gas industry for new field discoveries. At one stage the government fiscal take from new field developments was 30% of profits based on corporate income tax, with no other fiscal levies. The government take has been increased in past six years to over 50%.
- UK also operates a legacy system on historic large-field production licences. Government take for old legacy fields like Ninian and Forties is some 75% where petroleum revenue tax (PRT) still applies (a tax on profits from production with a number of complex allowances, safeguards and uplifts applied) but with a royalty finally removed in 2003.
- The U.K.'s North Sea fiscal regime has three tiers:
    1. Ring-fence corporation tax (RFCT), which is similar to the normal corporation tax regime but with 100% capital allowances on most capital expenditure and an enhanced exploration supplement (EES). The EES provides an annual uplift of 6% in the value of unused capital allowances due to qualifying exploration

and appraisal expenditures that are carried forward each year for a maximum of 6 years. In addition, the regime is ring-fenced, which prevents taxable profits from oil and gas extraction in the U.K. and the U.K. continental shelf (UKCS) from being reduced by losses from other activities.

2. 20% supplementary charge (SC) levied on oil and gas companies' profits as computed for the ring-fence corporation tax above, but without allowing a deduction for financing costs. This was introduced at a 10% rate in 2002 and extended to 20% starting in January 2006.
3. PRT is a special field-based tax currently levied at 50%. PRT does not apply to fields given development consent on or after 16 March 1993. PRT is deductible against RFCT and SC.

- This system applies equally to oil and gas.
- IOCs control much of the U.K. oil and gas infrastructure: key oil and gas pipelines to shore, gas processing facilities and oil storage and loading terminals. IOCs earn substantial revenues from third-party tariffs paid for access to this infrastructure. Access to this infrastructure on reasonable terms has proved to be a major obstacle for some independent companies and has delayed the development of some projects. It has also raised fiscal issues for the government in terms of taxation allowances and what is included as upstream and midstream infrastructure.
- The U.K. does not operate a norm price board as in Norway and the fiscal authorities have problems with the major IOCs in terms of establishing what are realistic market prices for short-term and long-term gas sales agreements, particularly where an upstream affiliate is selling gas to a midstream or downstream affiliate at lower than market prices to avoid higher upstream taxation. Clear rules and more transparent gas pricing would benefit the tax-raising authorities.
- The U.K. government was heavily criticised by the IOCs and U.K. service sector and industry representative groups for the introduction of the supplementary charge in 2002 and its increase to 20% from 2006. The criticism was based on the declining reserves and activity in the sector, which in the industry's opinion required incentives and not fiscal penalties. It was also criticised for the lack of consultation before the SC was imposed. The U.K. now has a reputation for fiscal instability, which reportedly has deterred some majors from making investments.
- The North Sea is a high-cost investment and operating area and has been so since the 1970s. There is not a sufficient competition in the specialist upstream service and construction sector and many service providers and suppliers have charged premium rates for offering services and supplies to North Sea operations. IOC profitability and government fiscal take is negatively influenced to a significant degree by this situation. Fiscal measures that encouraged more competition would probably both increase reserves and increase fiscal take and project profitability on a US$/boe basis.

United States

- The United States nationally employs a mineral-interest (concessionary or royalty/tax) fiscal regime. The U.S. is a federal system, and that each of the three levels of government – federal, state and local – has the authority to tax within its sphere, subject only to restrictions placed on it at the next higher level.

- The main fiscal elements are: upfront bonus; lease rental payments; royalty; production (severance and ad valorem) taxes (in some states, e.g. Alaska); state corporate income tax (SCIT); and federal corporate income tax (FCIT).
- State CIT is deductible against the federal CIT and the combined state and federal CIT rate lies in the approximate range 35% to 42% (see Figures 2.2.14 and 2.2.15 for more details on CIT).
- The U.S. government has received over $65 billion in bonuses for the Outer Continental Shelf since 1953. Bid bonuses in lease sales are amongst the highest in the world in terms of dollars/acre.
- Depending on land ownership, a royalty may be paid to private property owners (1/8 to 1/3 share); the state (1/8 to 1/5, with some reliefs for certain marginal and non-conventional activities, e.g. 1/12 or less); the federal government (1/8 onshore and 1/6 or higher offshore).
- An interesting incentive applied to some leases in Texas involves a lower royalty rate being locked in if wells are drilled earlier rather than later during the primary leasing period.
- Basic offshore federal royalty rate was one-sixth (16.67%) in offshore Gulf of Mexico (GOM) until 2008 when this was increased to 18.75% for new leases awarded.
- GOM operated a deepwater royalty relief scheme for leases issued from 1995 to 2000 that successfully stimulated industry investment. For example, the first 87.5 million boe of production for a field in greater than 800 m (2,624 ft) of water in such leases are exempt from royalty.
- Royalty relief was removed and royalty increased for March 2008 lease sales in GOM. However, Central Lease Sale 206 attracted US$3.7 billion in apparent high bids, setting a record in U.S. leasing history for high bids since area wide leasing began in 1983. In Lease Sale 206 the agency received 1,057 bids from 85 companies on 615 tracts. The industry still has an appetite for investment in GOM, even on tougher fiscal terms. This industry response has relevance for Alaska.
- EIA figures suggest that the bulk of U.S. oil reserves are located in just four regions: Texas (23%), offshore (19%), Alaska (18%) and California (16%). In addition Colorado, New Mexico, Utah and Wyoming together contain about 10% of the nation's oil reserves and about 30% of natural gas reserves. About 90% of onshore federal drilling permits were issued in those four states during the 2007 fiscal year. For this reason the production and property taxes are reviewed in some detail for those 6 states plus Alaska.
- The effective combined production taxes (severance plus ad valorem) in California, Colorado, New Mexico, Texas, Utah and Wyoming, taking into account various reliefs and exemptions, appear to be significantly lower than production taxes in Alaska.
- There have been several efforts in Congress to increase the federal government take from production in U.S. waters. Most notably, the 2007-2008 Congress failed to pass

legislation that would have imposed a 13% excise tax on future GOM production. Some are predicting that similar fiscal tightening measures may be adopted in 2009 under a new administration and new Congress. Such measures could include royalty rate increases, the possible introduction of a windfall profits tax and applying tougher limitations on foreign tax credits.

- Congress did, however, approve legislation in October 2008 that included several provisions increasing the federal government take from oil and gas producers. The legislation also extended renewable energy tax credits, using the increased tax revenues from oil and gas producers to partially cover the tax credits. The tax-increase provisions include changes in manufacturers' taxes, tightening the rules on oil and gas producers' income earned overseas and increasing producer payments to a federal oil spill liability fund. Congressional estimates put the increased government take at $6 billion over the next 10 years – down significantly from what proponents of the tax provisions had first pushed to achieve.