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

BY
DAVID WOOD
NOVEMBER 2008

For

State of Alaska
Legislative Budget & Audit Committee

David Wood & Associates
www.dwasolutions.com

Section 3.1

Features and recent evolution of Alaska's prevailing fiscal design

Part 3: Evolution of Alaska's Fiscal Design and Gas Reserves

3.1 Features and recent evolution of Alaska's prevailing fiscal design

Elements of Alaska's Prevailing Upstream Oil & Gas Fiscal Design

The state of Alaska has five major sources of revenue from the upstream petroleum industry.

- Royalty (~12.5% in most cases)
- Basic production tax, BPT (25%)
- Progressivity increment to BPT (0% to 50%)
- Property tax (~2% on oil and gas property assets)
- Alaska corporate income tax, CIT (9.4%)

In addition to these major sources of revenue there is also a conservation surcharge of US$0.05 per barrel charged only on oil to help pay for the environmental impacts of spills, etc. It does not apply to natural gas. The conservation charge is not deductible for production tax or royalty, but is deductible for federal and state income tax. Oil prices would have to be extremely low before the conservation charge had a discernable impact on the state take, so it is not considered further in this gas-focused study other than to remark upon its regressive structure, being charged on production quantities rather than sales (not that this has any practical consequences because of the very low level of the fee).

Several of the major tax components are more discernibly regressive in nature, particularly property tax, royalty and a floor imposed on production tax. That said, there are fiscal elements in the prevailing design that moderate some of the regressive elements. These include a range of investment credits on capital expenditures (some of which can be traded or sold to the state rather than held until they can be applied against production tax liabilities) and some royalty reliefs. The major fiscal revenue-raising and the important offsetting mechanisms will be discussed in more detail in this section together with a discussion of the impact of recent changes to Alaska's fiscal design.

The methodologies applied in calculating each of the major fiscal elements are reviewed below, but it is important initially to grasp how the fiscal elements work together to form a functioning fiscal design. Figure 3.1.1 is a flow diagram illustrating the status quo fiscal design and how the five fiscal components are integrated, work in sequence and contribute to Alaska tax revenues and the post-FIT cash flows (i.e. post all government taxes and royalties) of production companies.

Figures 3.1.6 and 3.1.7 (in two parts) at the end of this section provide definitions of valuation terminology adopted for this study and a single-year fiscal calculation example on which the fiscal modelling logic is based. These items were agreed in discussions with the other Legislative Budget and Audit Committee consultants during 2008.

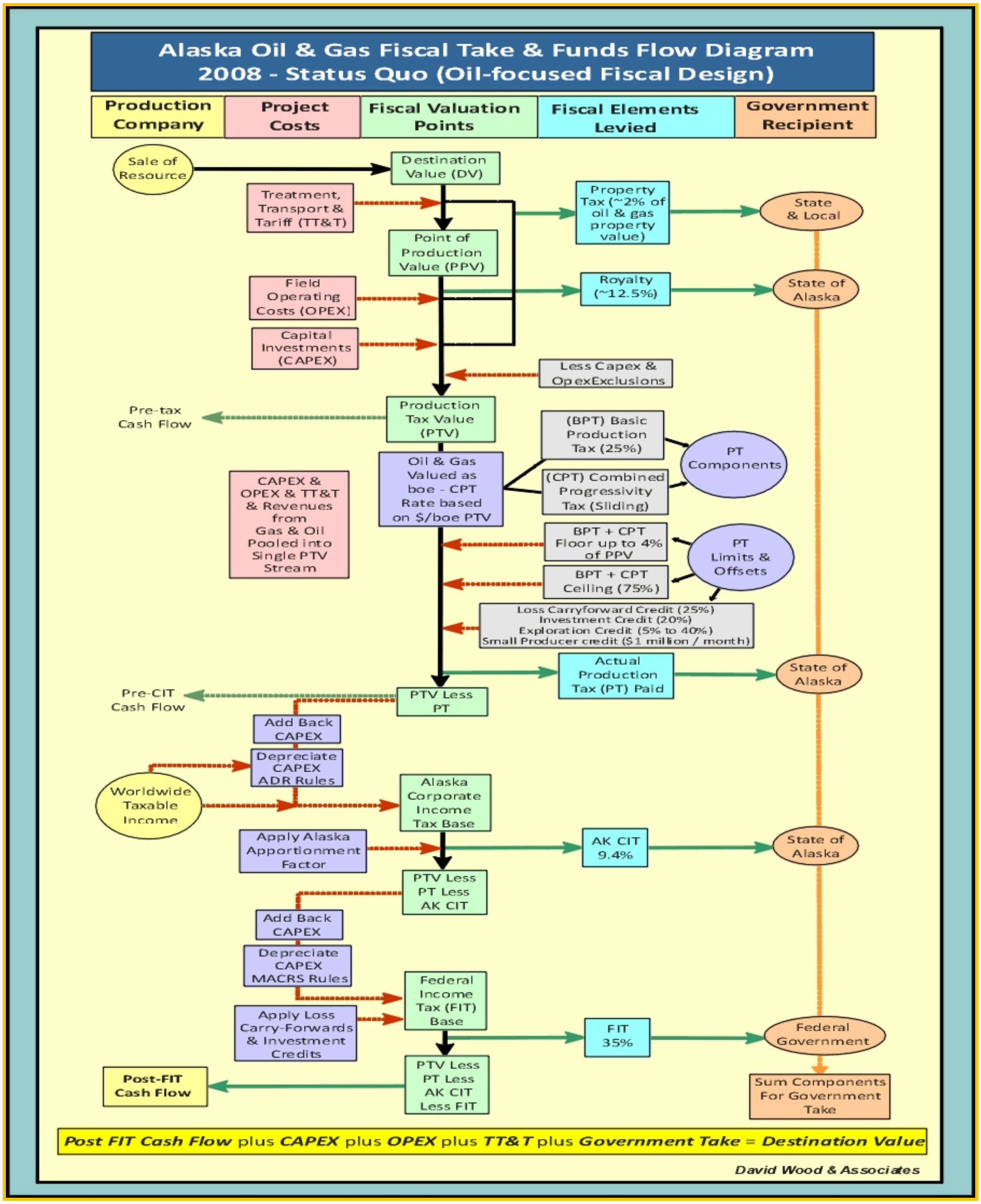

Figure 3.1.1 Flow diagram for Alaska upstream oil and gas fiscal design. This is the methodology used for the base-case fiscal model used for analysis. (See also Figure 4.3.7)

Alaska Tax Rates Modelled as a Base Case

The rates applied to the Alaska fiscal elements in the base case Excel workbook model used in this study are listed in Figure 3.1.2.

Fiscal Terms		
Royalty Rate (%)	12.50%	
Alaska Basic Production Tax BPT (%)	25.00%	
Investment Credit (%) of Capex	20.00%	
Alaska CIT Rate (%)	9.40%	
Federal CIT Rate (%)	35.00%	
Approximate Combined Federal + State CIT Rate (%)	41.11%	not used

Figure 3.1.2 Key rates of Alaska's fiscal system. Property tax of approximately 2% of oil and gas property value is also levied in three separate components (on TT&T, Opex and Capex). Alaska's BPT and the progressivity component of the production tax and investment credit were introduced in the fiscal changes legislated in 2006/2007. All other tax and royalty rates and mechanisms remained unchanged in the 2006/2007 round of changes.

The spreadsheet model used for the quantitative work presented in this study has the ability to vary the rates of these key fiscal elements to evaluate the impact of other fiscal designs on specific fields. It also focuses specifically on the progressivity tax methodology and possible alternative mechanisms that could improve its efficiency with respect to natural gas. Much of the sensitivity analysis presented in subsequent sections of this study addresses the impact on field economic performance and fiscal take of the prevailing progressivity tax mechanism and alternative mechanisms for this fiscal element. It is recognised that many other fiscal design issues also require consideration in evaluating the overall performance of a fiscal design and its suitability for encouraging the development of natural gas resources. From Alaska's perspective some of these issues are considered below.

Costs Eligible for Tax Deductions

Historical development of production taxes in Alaska has involved a critical distinction for fiscal purposes between:

- ***Upstream costs*** (i.e. finding and development capital costs associated with exploration and lifting costs associated with production operations) incurred before the hydrocarbon (i.e. oil, gas or NGL) reaches the ***point of production***; and

- **Transportation, Treatment and Tariff** or **TT&T** costs (Typically called ***downstream costs*** in Alaska) to transport the produced hydrocarbons to market.

Until 2006 for both royalties and severance (production) taxes, only TT&T costs were deductible (although at Prudhoe Bay and some other older units an agreed upon upstream field cost allowance adjusted for inflation could be deducted for the royalty calculation.) Defining the point of production was critical to establish what investments could be deducted for severance tax purposes. After the 2006/2007 tax reforms, both allowable upstream and downstream costs are deductible in calculating the production tax value (PTV) tax base, so the point of production has become less significant from a fiscal perspective. However, it still determines which investments are eligible for tax credits. Except for certain exclusions, most capital invested upstream of the point of production qualifies for the 20% investment credit.

If new investment is made in newer upstream leases, there is no field cost deduction allowed from the point of production value on which royalty is based. The Department of Natural Resources (DNR), which is in charge of the state's royalty program, had discouraged allowing field costs deductions for new leases. However, if new investments in Prudhoe Bay or other older production units generate new production, field costs may still be deducted from royalty on that production. For BPT purposes, except for certain enumerated exceptions, upstream capital is deductible as invested, and operating and lifting costs are deductible as they are incurred (no depreciation or amortization is involved).

Transportation and Gas Processing Plants and Tariffs

Alaska has quite specific fiscal definitions for what is upstream and what is downstream in the natural gas supply chain: 1) Gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, or 2) the first point where gas processing is completed, or 3) where gas treatment begins, whichever is further upstream is considered to be the "point of production". As illustrated in Figure 3.1.3, gas processing, gas treatment and point of production are defined so that gas processing is upstream of the point of production and gas treatment is downstream of the point of production.

Downstream investment in transportation pipelines or other publicly regulated facilities such as gas treatment plants often yield tariffs or tariff like charges that are deductible for both royalty and production taxes. ***Gas treatment*** which Alaska defines as "*conditioning gas and removing from gas non-hydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into gas pipeline systems*" (and which may include the incidental removal of liquid hydrocarbon) ***is downstream of the point of production***. Thus, for the BPT tax base and royalties the tariff earned or paid at a gas treatment facility will be deductible (although it may be an artificially constructed fee rather than published tariff depending on its regulatory status).

For BPT purposes, ***gas processing*** is defined in Alaska as "*processing a gaseous mixture of hydrocarbons (i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule Thompson effect, or another physical process that is not mechanical separation; and (ii) for the purpose of extracting and* *recovering liquid hydrocarbons*" and it ***is upstream of the point of production***. As upstream capital it should qualify for the 20% investment credit.

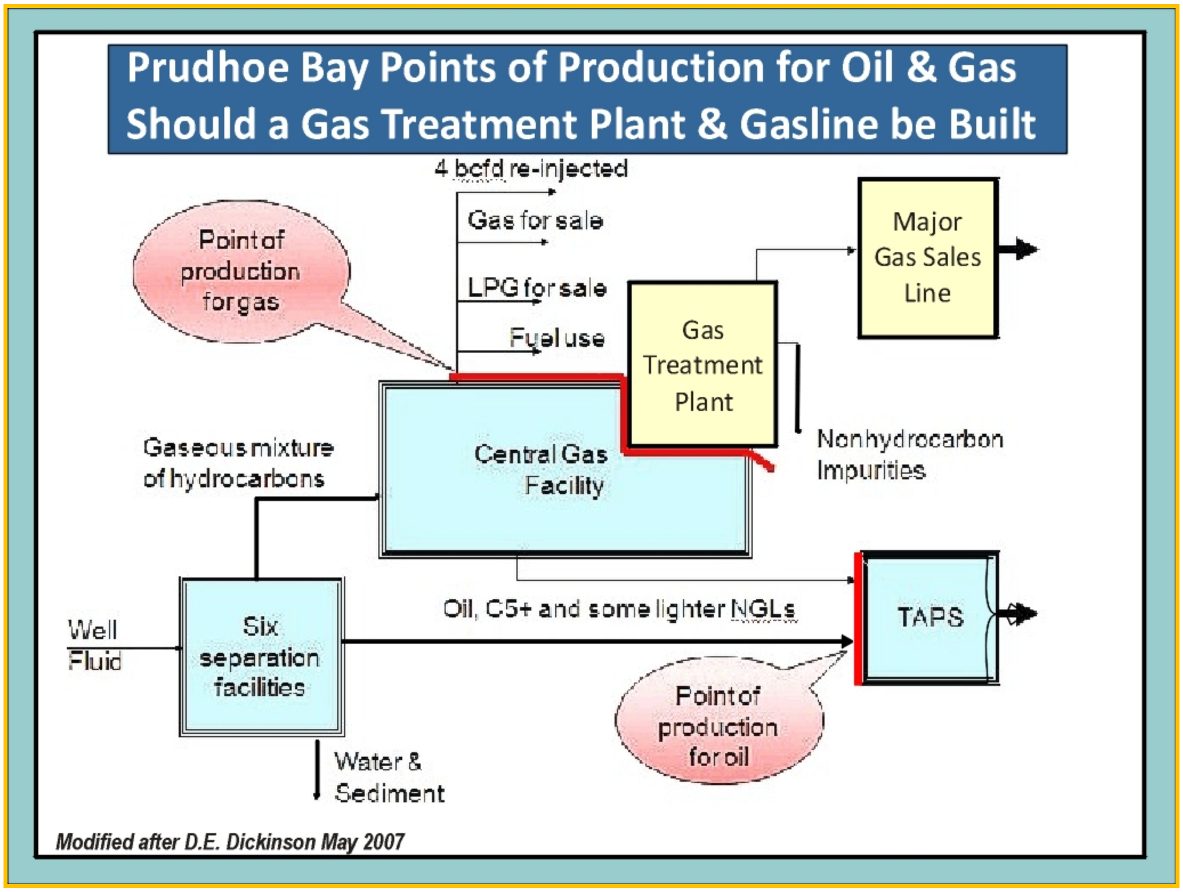

Figure 3.1.3. Upstream and downstream fiscal designs are separated by the point of production. This diagram makes the hypothetical assumption that a gas treatment plant and major gas sales line are built in Alaska.

The risk for fiscal revenues (i.e. from Alaska state perspective) is that: 1) some gas processing costs could move downstream of the point of production, leading to inappropriate inflation of TT&T costs for third-parties, and 2) gas treatment plant(s) associated with a pipeline move upstream of the point of production and result in the state paying 20% of the capex (in the form of investment credits) plus the marginal tax rate of the facilities upfront rather than having them depreciated over a long period as part of downstream capital investment.

Fiscal Treatment of Natural Gas Liquids (NGL) Including Liquid Petroleum Gas (LPG)

Fiscal treatment of NGLs remains a gray area for future natural gas projects in the sense that different components (e.g. ethane, LPG and C5+) may be extracted from the wet natural gas production stream and monetized in various ways and in various places in Alaska, Canada and Lower 48. Under prevailing legislation there is no distinction made between any liquids extracted from a gas production stream. A stream of heavier hydrocarbon natural gas liquids (C5+) extracted from the some 8 bcf/day of natural gas (the dry gas residue of which is re-injected at Prudhoe Bay) is sent by pipeline to the TAPS crude oil export pipeline, where it is commingled with the crude oil stream and sold as part of it.

For future natural gas production projects three main alternative export options can be considered: (1) if the major gas sales pipeline is built to Canada, wet gas exported from Alaska would also move to the existing Empress (lighter NGL extraction) Complex in Canada; (2) building new lighter NGL extraction infrastructure in Alaska and exporting mainly dry gas; (3) extracting a minor component of lighter NGLs to meet local market demand in Alaska but exporting most gas as an NGL-rich wet gas.

These alternatives all pose questions concerning how the revenue streams from NGLs and the costs of the infrastructure should be dealt with from a fiscal perspective. Under the current system, no distinction is made between taxing oil and gas; so, the NGL revenue streams are treated the same as crude oil, since they are spiked into the crude oil and sent down the TAPS. Depending upon oil and natural gas prices and commingled crude oil compositional constraints it may make sense for operators in the future, on some occasions, to separate and liquefy C4 from the natural gas stream and spike it into the C5+ stream into TAPS to attain higher prices from that stream. On other occasions it may make sense to keep the C4 in the gas stream and send it down a high-calorific gas line. The same gas treatment plant may have the ability to do both. The revenue stream and the facility could then conceivably be switching from a liquid revenue stream to a natural gas stream from time to time.

Carbon Dioxide Re-injection

Irrespective of any federal mandates that may emerge in the next few years concerning the handling and taxation of carbon dioxide emissions from upstream gas production projects, there is an industry expectation that ultimately CO_2 separated from the natural gas produced from some of Alaska's CO_2-rich natural gas reservoirs is likely to be re-injected into Prudhoe Bay and/or other reservoirs. Possibilities to use CO_2 in miscible flood enhanced oil-recovery projects are being evaluated, but injection may be required merely as a sequestration or disposal requirement.

The issue that CO_2 may be derived from a range of fields and then, downstream of a gas processing plant, be re-injected into another field complicates its fiscal and contractual treatment. Complex negotiation will be required among the field equity owners and fiscal authorities to establish how CO_2 is to be handled and how processing and re-injection costs are to be split and treated for taxation purposes and which bodies hold the liabilities associated with it. Irrespective of such issues, constructing infrastructure to handle it will add substantial capital and operating cost to future gas field development projects and will probably require some tax incentives to make such projects commercially viable.
An Alaska gas line will probably have to deal with eventual federal greenhouse gas emissions laws, which can be expected to increase the cost of delivering gas through the pipeline. The state should consider such requirements in formulating its fiscal design for natural gas.

Fiscal Treatment of Decommissioning Costs

Decommissioning costs are generally of secondary importance in fiscal design, having a relatively minor impact on overall fiscal performance. Under current Alaska regulations, decommissioning ("dismantlement, removal, surrender or abandonment") costs are not deductible for the PTV base on which BPT is levied or the PPV base from which royalty is calculated. Such costs are, however, deductible for both state and federal income tax purposes, and also lower the property taxes on any facility being valued on its full life cycle cash-flow basis.

A Brief History of Recent Changes to Alaska's Fiscal Design

Governor Frank Murkowski presented his PPT plan, referred to as the "PPT 20/20" plan, focused primarily on oil, to the 2006 Alaska legislative session as a proposed replacement for the production tax in the existing fiscal design for Alaska. The existing production tax was referred to as the Economic Limit Factor (ELF) severance (production) tax. The ELF tax rate was based on per-well and per-field oil production volumes (which produced bizarre results), but involved no profitability or oil-price driver. ELF, with certain modifications, had been in operation for more than 20 years, and because it was production-driven it was limited in its ability to provide Alaska with appropriate shares of economic rent in high-price environments.

Up to 2006 the fiscal design for natural gas involved severance tax payments in cash at a 10% rate on gross gas value (excluding royalty gas) or a minimum 6.4 US cents/mcf, either reduced by ELF to an average effective rate of 7.25% (Department of Revenue (DOR), May 24 & Nov 16, 2006). For oil the severance tax was 12.5% for the first five years and 15% thereafter, subject to a minimum payment of US$0.80/barrel with either reduced by the ELF to an average effective rate of 8.5% (DOR, Revenue Sources Book, Spring 2006).

Both pre- and post-2006 other fiscal elements for oil and gas production have remained unchanged. These include: from state leases a royalty usually 12.5%, though higher in some newer leases (taken either in kind or in value); property tax payments at a maximum of 20 mills (2%) paid in cash and shared between the state and municipalities; and corporate income tax based upon a taxable income of companies with a maximum 9.4% rate for taxable income greater than US$90,000 per year.

The PPT 20/20 as proposed in 2006 involved a 20% profits-based tax to replace the severance tax, maintaining the royalty, property tax and income tax components of the older system and introducing a 20% PPT tax credit for capital expenditures. The mechanism envisaged was that tax credits would to some extent (several percentage points, depending on project costs) mitigate the 20% PPT rate. The mechanism as presented was criticised widely, generally on two fronts, (1) it did not provide Alaska with sufficient upside in high-price environments and was regressive at low prices and high costs due to the strong impact of royalties; 2) in effect the opposite criticism, that it was a net tax rather than a gross tax, with many legislators and others preferring a gross tax to avoid their fear that producers would somehow "game" the state over net.

During the 2006 Alaska legislature, the oil producers and service companies lobbied extensively against an increased tax rate on the basis that it would inhibit future investment and cost jobs. On the other hand, a section of public opinion favoured a more assertive windfall profits tax on oil and gas companies.

To compensate for the regressive shortcomings of the PPT 20/20 proposals the Alaska legislature passed (August 2006) an amended fiscal design (tax bill) including a 22.5% PPT rate and a progressivity component to the tax (levied on the combined revenue stream of oil and gas converted on an energy equivalent basis to barrels of oil equivalent – referred to in this report as combined progressivity tax or CPT) which effectively increased PPT rates by 0.25% for every dollar the production tax value (PTV) per boe unit for the tax period is above US$40/boe.

Governor Murkowski's popularity plummeted due in part to the public debate surrounding changes to oil and gas taxes and his failure to deliver a North Slope gas pipeline, which he had been negotiating with the major oil companies since 2004 under the terms imposed by Alaska's Stranded Gas Development Act. He placed a distant third in the Republican primary election of August 2006 and Sarah Palin was elected governor in November 2006. Subsequently, following FBI investigations, a number of participants in the 2006 legislative process have been indicted, convicted or pled guilty to various bribery and corruption charges, including several legislators, oil field service company VECO's two top officers, and Gov. Murkowski's chief of staff. Citing the proposition that this provided a difficult environment in 2007 for the Alaska legislature to establish credibility for the production tax changes approved in August 2006, the newly elected Alaska governor, Sarah Palin, asked the legislature to review the PPT mechanism adopted in 2006 with a view to amending it and removing any taint of corrupt influences.

That review resulted in amendments to production tax rates being signed into law in December 2007. The basic production tax rate BPT was increased to 25% and the progressivity component of the tax (CPT) was made more progressive: the new CPT increases the BPT by 0.4% for every dollar the PTV for the month is above US$30/barrel up to US$92.50/barrel. For higher PTVs the progressivity adjustment increases the BPT rate by 0.1% for every dollar the PTV for the month is above US$92.50/barrel to a ceiling of $342.50, which equates to a maximum progressivity component (CPT) of 50% and a maximum total production tax (BPT plus CPT) of 75% .

Impact of Fiscal Reforms

The application of the progressivity fiscal element and previous fiscal reforms have had a dramatic impact on Alaska upstream fiscal revenues since 2007 because of the high oil prices that have prevailed throughout 2008.

The tax burden on the producers has more than tripled between fiscal year (FY) 2006 and FY 2008 and almost quadrupled between FY 2004 and FY 2008. The State of Alaska's fiscal years runs from July to June, so FY 2008 ended just a few months ago.

As there was an administrative change in the way the ELF was applied in 2005, FY 2004 was the last year of collections under a regime that had been stable for some time. Figure 3.1.4 (Dickinson, 2008) shows that production taxes of $4.9 billion in 2008 were $4.3 billion higher than the $.7 billion collected in 2004, almost an eight-fold increase. This is due partly to prices being much higher in 2008, but price increases are to some extent offset by far fewer barrels being produced in 2008 than in 2004. FY 2004 was the last year Alaska produced over a million barrels a day.

	Fiscal Year	Prod Tax Rev	2008$ / 2004 $	WC Price	Million bls daily Prod	Million bls annual Prod	Price times volume	2008$ / 2004 $	Increase
		(A)	(B)	(C)	(D)	(E) = (D) * 365	(F) = (C) * (E)	(G)	(B)/(G)
Fall 2007 History	2004	651.9		31.74	1.004	366.5	11,631.4		
Fall 2007 History	2005	863.2		43.44	0.936	341.6	14,840.8		
Fall 2007 History	2006	1,199.5		60.80	0.863	315.0	19,151.7		
Spring 2008 History	2007	2,208.4		61.83	0.758	276.7	17,106.5		
Spring 2008 Forecast	2008	4,940.5	7.6	85.73	0.734	267.9	22,967.9	2.0	3.8

Figure 3.1.4 Three plus fold increase in taxes due to fiscal reforms (Dickinson, 2008).

Figure 3.1.4 adjusts for price and volume variance in column (F) by calculating the product of production and price. That product essentially doubled between FY 2004 and 2008. Combining those two ratios shows that relative to that standard, taxes were three and a half times higher than what they had been a few years earlier (380% increase). The impact of the 2006 reforms show up in the FY 2007 numbers, and the 2007 reforms first show up in FY 2008 numbers.

This analysis testifies to the potential impacts of progressive fiscal adjustments.

Some new oil field developments go ahead in Alaska, but natural gas field developments continue their 30+ year wait for a pipeline.

In January 2008, Eni (Italian, part state-owned, major IOC) sanctioned full-field development investments of US$1.45 billion to develop the Nikaitchuq oil field on the North Slope of Alaska with first production scheduled for year-end, 2009. This announcement demonstrates that at least some large companies see the fiscal revisions of 2006/2007 as workable and had not made projects unattractive to investors as some producing companies had claimed.

The Nikaitchuq field is situated in water depths averaging 3 m deep. The development plan includes some 35 production wells and 35 injection wells. Some one-third of the wells are to be drilled from onshore locations and the remainder are to be drilled from an offshore artificial island built 4.5 km from the coast. Production will be sent to a newly built 40,000 barrel/day processing facility onshore near the field and then transported some 22 km to the Kuparuk network and onward into the Trans-Alaska Pipeline System. Nikaitchuq has reserves estimated at 180 million barrels of oil.

Pioneer commenced production from Oooguruk field (Pioneer 70% and operator; Eni 30%), located some 25 km west of Nikaitchuq, in June 2008.

In April 2008, Alaska's Natural Resources Commissioner rejected the oil major companies' (ExxonMobil operator with partners BP, Chevron, ConocoPhillips and others) 23rd development plan for Point Thomson field as it involved no commitment to produce gas (only condensate extracted from the gas) and due to skepticism of the companies' intentions to proceed with development. The Point Thomson Unit (PTU) on Alaska's North Slope east of Prudhoe Bay is a gas-condensate field covering some 106,200 acres (covering 45 state oil and gas leases), which has no current production, and consists of a high-pressure reservoir with operator-estimated reserves of more than 8 tcf of gas and 200 million bbl of condensate. The DNR believes potential reserves are higher than the operator for PTU.

The lessees contend that ultimate production from PTU depends upon the construction of an Alaska gas pipeline to the Lower 48. In 2008 the state awarded a license and subsidy to TransCanada to proceed to an open season and to apply to the Federal Energy Regulatory Commissions (FERC) for a certificate for such a line. Both TransCanada and the lessees with most of the known North Slope gas reserves have expressed concerns about fiscal issues for gas production.

Fiscal Certainty and Gas Pipeline Progress

The proposed Alaska gas pipeline has its roots in longstanding efforts to access the natural gas under the North Slope. Much of the gas is held in oil-producing areas leased by the international oil companies, with BP, ExxonMobil and ConocoPhillips holding the largest interests. There have been discussions to develop a plan to tap the gas since 1969, just a year after the giant Prudhoe Bay oil and gas discovery, but market prices for gas were far below pipeline costs until 2001-2002, when higher prices rekindled interest in the Alaska line. Since then, the oil and gas operators have been unwilling to assume the huge cost liabilities of building a pipeline and the risk of market prices without considerable fiscal assurances. The State of Alaska has perceived for the past several years that major oil companies were demanding substantial concessions from the state with no guarantee or commitment to actually build a gas pipeline or prove up additional gas reserves. This stand-off between state and the oil and gas operators, together with fluctuating U.S. gas prices and fears of construction cost overruns, has meant limited progress toward the gas pipeline project.

Governor Palin has consistently asserted that her administration will not negotiate fiscal terms with the oil and gas producing companies. In March 2007, the governor presented the Alaska Gasline Inducement Act (AGIA) as her plan for building a natural gas pipeline from the state's North Slope. The legislature approved AGIA, and the measure was signed into law in June 2007. In January 2008 it was announced that a Canadian company, TransCanada Corp., was the sole AGIA-compliant applicant. Focused on the pipeline itself, the AGIA offers few fiscal assurances to producers taking capacity in an Alaska gas pipeline.

Fiscal certainty is a contentious issue in Alaska in discussions concerning a gas pipeline. Some suggest that any fiscal regime for a gas pipeline should include gas tax stability clauses for producers, but that might require a state constitutional amendment. Major oil and gas producing companies have in the past sought fiscal incentives to support and invest in the multibillion-dollar long-term gas pipeline project, including 30 to 35 years of fiscal certainty on state fiscal terms agreed upon before the companies would be willing to start design and permitting work on the project.

The dialogue to resolve such issues has yet to take place under the Palin administration. Governor Palin and TransCanada recognise that workable fiscal terms will be needed for any gas pipeline project, but the governor says she will only support special terms and incentives for gas transported through the TransCanada project under AGIA. Governor Palin stated prior to the June 2008 special session of Alaska’s Legislature that she supports TransCanada's proposal over the producers' Denali project (see below) because the Canadian company has agreed to the state’s explicit conditions on pipeline expansion, third-party access and a tariff structure.

Gas Pipeline Progress up to October 2008

In July 2008, the Alaska legislature met in special session to consider the proposed state AGIA license for TransCanada to develop the Alaska natural gas pipeline (1,715-mile, 48-inch-diameter pipeline from Alaska’s North Slope to the Alberta gas hub). TransCanada estimates the project will cost at least $26 billion, though consultants to the legislature estimate the cost at $30 billion. Governor Palin recommended that the Legislature approve the license, entitling TransCanada to receive up to a US$500 million in state funds to help cover the expenses (and risk) of project design and planning and to defray regulatory and other costs, plus certain other incentives outlined in the AGIA. The legislature approved the exclusive license for TransCanada, and the governor signed the legislation September 15, 2008. As of this writing (November 2008) the license is scheduled to be issued in November 2008.

There is still a long way to go before a gas pipeline is constructed, and there is no guarantee yet from TransCanada that it will actually be built. The award of the state license could represent a first tangible step in building a framework for the project to move forward. TransCanada's schedule calls for the company to file an application with the FERC by the end of 2011, with the expectation that the pipeline would be completed and operational by late 2018. However, TransCanada is not obligated to proceed with the project even if it clears all the financial and regulatory hurdles. For such a commitment to materialize, TransCanada needs to secure gas shipping commitments for all or a substantial portion of the planned pipeline's capacity. As the major IOCs control the majority of the North Slope proven natural gas reserves, their involvement in making such commitments is required before 2011 for TransCanada to achieve its schedule – whether by undertaking the commitments themselves or committing to sell gas to a party that is credit worthy enough to then undertake the commitments.

TransCanada plans to begin an open season to seek capacity commitments in early 2010, concluding the bidding by 30th June 2010, according to its schedule announced in September 2008. Meanwhile, it is proceeding with work toward certification of the project by FERC and Canada's National Energy Board (NEB). The FERC and NEB certificates are required to construct and operate the pipeline. Requests for proposals for engineering and environmental studies are soon to be issued. TransCanada is planning to spend some $80 million preparing for the open season (with half of the expenses reimbursed by the State of Alaska under terms of the AGIA license).

Denali Gas Pipeline Alternative

On 8th April 2008 major oil producers BP and ConocoPhillips announced their intentions to proceed with their own pipeline proposal, called Denali – The Alaska Gas Pipeline. That producer-led proposal, because it is being progressed outside AGIA, would receive no Alaska state reimbursement for design, planning or permitting expenses. However, the companies recognise the need to negotiate a workable fiscal design for the upstream and midstream components of the project with the state.

The Denali pipeline as conceived would contain capacity to move some 4 bcf/day of natural gas to Lower 48 markets. Just like the TransCanada proposal, it would be the largest private-sector construction project ever built in North America. BP and ConocoPhillips announced plans to spend US$600 million to reach the first major project milestone, an open season, commencing before year-end 2010. Denali LLC plans to award major engineering contracts in the first quarter to 2009 to help prepare cost estimates. Following a successful open season, a process during which the pipeline company would seek customers to make long-term firm transportation commitments to the project, the company would focus on FERC and NEB certification required to move toward project construction. The FERC and NEB certificates are required to construct and operate the pipeline. Alaska state approval is not required by FERC or NEB, but state opposition to a specific gas pipeline proposal would make it more difficult to obtain FERC and NEB approval.

Denali LLC in summer 2008 started field work in preparation for an initial open season in 2010 and plans to place up to 400 people in the field in 2009 compared to 80 in 2008. Much of the US$600 million budget will be spent on environmental and engineering work to develop cost estimates for the open season.

Alaska contractors have suggested that both pipeline groups – TransCanada and Denali -- will face challenges in 2009, as they will compete for support contractors and consulting companies from a relatively small pool of groups familiar with Alaska conditions.

Detailed Issues Associated with Certain Fiscal Elements

Royalty and its Potential Relief

Royalty is levied at a rate typically 12.5% on point of production revenue (PPV), which equates to destination values less TT&T costs. Exact royalty rates and structures vary depending upon the location, land ownership and age of the lease. The Department of Natural Resources (DNR), the state agency responsible for royalties, has the right to lower the royalty rate to as low as 5%, if the pool has not been produced, and to as low as 3% for a producing lease, if it is considered that such an adjustment will either bring the lease into production, prolong existing production, or prevent production from being shut in.

To be eligible for the 5% royalty modification an oil or gas field or pool has to be sufficiently delineated to the satisfaction of the commissioner. Also the field or pool should not previously have produced oil or gas for sale, and oil or gas production from the field or pool must be shown to not otherwise be economically feasible. The commissioner may not grant a royalty modification unless the lessees requesting the royalty modification make a clear and convincing showing that a royalty modification meets all these requirements and is in the best interests of the state.

The Nikaitchuiq field, operated by Eni was granted royalty relief on this basis in 2008.

The Alaska legislature passed a bill in 1998 which reduced the royalty rate to 5% for the first 25 million barrels of oil and 35 bcf of gas produced from six Cook Inlet fields. Hence, Alaska has a track record of issuing royalty reliefs to help projects achieve commerciality.

In this study royalty relief is not considered as part of the base-case assumptions. However, it is noted that as royalty is one of the most regressive elements of the Alaska fiscal design, royalty relief for marginal projects or in adverse market conditions will be viewed very positively by those companies considering making upstream investments, particularly exploration. Devising mechanisms to overcome the regressive nature of royalty and property tax is also a relevant issue for gas progressivity taxation as discussed in some detail in Section 4.6.

Property Taxes

Most of the property tax goes to the North Slope Borough and other municipalities. The total tax is 20 mills, or 2% of the assessed value of oil and gas property in the state. The three components of a producer's assets subject to property taxes are:

(1) Production property (62% of 2008 tax roll) valued at cost during construction and then replacement cost new less depreciation (based on economic life of proven reserves) thereafter.
(2) Pipeline property (37% of 2008 roll) valued at cost during construction “with due regard to the economic value of the property based on the estimated life of the proven reserves…” thereafter.
(3) Exploration property (e.g. rigs) (1% of 2008 roll) valued at sales value.

Property taxes are a regressive element because they are still payable in periods when projects generate low or negative cash flows.

Progressivity Tax

In high oil price environments a substantial portion of Alaska tax revenue comes from the progressivity component of production tax – referred to here as combined progressivity tax (CPT) in the system signed into law in 2007. CPT is referred to as “combined” because it combines the revenue streams (less allowable costs) from all sources of petroleum production (crude oil, C5+, natural gas and other NGLs if any) into a single production tax value (PTV) divided by the total barrels of oil equivalent produced to provide a PTV in unit terms (per boe).

The thresholds defined for CPT are expressed in PTV per boe terms, although when conceived these thresholds were tuned with oil production, revenue streams and prices in mind, not natural gas. Although treating oil and gas together for the CPT calculations facilitates an easier calculation, it leads to some inefficiencies in this fiscal instrument, as the sensitivity analysis presented later in this report shows. Any natural gas production tax values are currently converted to barrels of oil equivalent (boe) at a rate of 6 million British Thermal Units (mmbtu) equal 1 barrel of oil for the CPT calculation.

This means that gas revenue streams are included in the BPT and CPT (progressivity) tax base (PTV) on an energy-equivalent basis. This would not be a problem if oil (C5+) and natural gas were: 1) selling at prices that equated to energy (btu) parity; and 2) they cost the same in $/btu to transport to their destination markets. In 2008 gas and oil in no way approximates this parity situation. If an Alaska gas pipeline existed to Canada and gas sold at $7.5/mmbtu ($45/boe destination value) with a $4.5/mmbtu TT&T cost ($27/boe), the gas PPV netback would be some $18/boe. Contrast this with oil selling at about $100/barrel (it was $130/barrel in July 2008), with a TT&T cost of some $6/barrel the oil PPV netback would be some $94/barrel (some five times the gas netback). Averaging in the gas and oil PPVs in a combined value stream would mean the low-value gas would substantially dilute the PTV/unit boe value on which progressivity tax is based and lead to a substantially lower tax payments to the state. For price parity on an energy basis to be achieved oil prices (Alaska North Slope West Coast (ANS WC) prices) would have to fall to about $24/barrel (in which case no progressivity would be due) or gas prices (AECO) would have to rise to about $17/mmbtu.

How Does CPT Methodology Work Under the 2007 Tax Law?

Under current law, as described above, PTV is converted to per unit basis by dividing total PTV dollars by taxable barrels (with taxable gas converted to barrels on an Btu-equivalent basis). If that per-unit value is below $30/boe, there is no CPT liability.

Any amounts of per-unit PTV calculated between $30/boe and $92.50/boe are translated into a CPT percentage at a rate of 0.4% per dollar PTV. The progressivity tax adds 0.4% to the tax rate for each dollar above $30/barrel at point of value, up to $92.50 per barrel, and thereafter an additional 0.10% to the tax rate up to a maximum point of value of $342.50. This yields a maximum total of 50% (CPT) tax rate.

CPT is calculated on a monthly basis and therefore has the ability to capture revenue from short-lived price spikes. For the generic modelling conducted for this study CPT is calculated annually using the thresholds and rates specified above, but for real producing assets a monthly calculation is required.

The CPT is then added to the 25% BPT, and that tax rate is applied against the PTV. This means the highest total nominal rate to be applied against the PTV is 75% and for this to be realised PTV unit boe would have to be $342.50 (and market oil prices higher than that to allow for TT&T and allowable cost deductions).

Production Tax Floor Provisions

There is a minimum payment or floor tax payment that must be made for production tax whenever the floor payment is larger than the regular BPT (and CPT) referred to here as the production tax floor provision. That payment is variable, but since the highest that payment can be is 4% of PPV (i.e. the royalty base not PTV) it is not likely to be triggered except: (a) at very low prices when 25% of PTV is lower than 4% of PPV; (b) when a producer has made large investments in a period and those investments overwhelm the value from its production sales.

The production tax floor payment is calculated as a percentage of the PPV. That percentage depends only on the price of oil at destination, as follows:

For ANS WC prices of $15 and less, there is no production tax floor payment.

For ANS WC prices above $15 but not more than $17.5, it is 1%.

For ANS WC prices above $17.5 but not more than $20 it is 2%.

For ANS WC prices above $20, but not more than $25 it is 3%.

For ANS WC prices $25 and above it is 4%.

However, the making of a production tax floor payment has no effect on the loss carry-forwards through the generation of credits that can be deducted from future production tax liabilities or the ability to create and sell or carry forward 20% investment credits.

The floor applies to the combination of BPT and CPT. Thus there is the unlikely but possible scenario where there were dramatic price changes in some months requiring a producer to make some progressivity payments, but for the year overall prices were low and that producer has to make a production tax floor payment. In modelling terms to test for minimum floor payment liabilities it is necessary to compare (a) the relative percentage of PPV under the floor provisions (oil price dependent) to (b) the 25% of PTV under the BPT provisions plus any progressivity payments made.

Loss Carry-forward Provisions for PTV Calculations

The loss carry-forward mechanism involves calculating a loss carry-forward credit by taking 25% of any prior year lease expenditures which were not used to calculate a PTV. By definition PTV cannot be reduced below zero. If eligible lease expenditures could have the effect of driving the PTV below zero in any year, they are instead transformed into loss carry-forward credits at 25% - the same rate as the BPT. Each year in the PTV calculation either PTV or that year's lease expenditures must go to zero in the tax calculation. If PTV is brought to zero and there are still outstanding lease expenditures, they are transformed into loss carry-forward credits at 25%. If lease expenditures are brought to zero and there is still PTV, then a tax liability is calculated on the remaining PTV at 25%.

Once transformed into credits, loss carry-forwards can be held onto and applied against future liabilities over two years, sold to other parties that might have current liabilities, or under certain circumstances sold to the state.

Dealing with loses in the form of carry-forward credits allows investment to lower taxes in future periods.

Investment Credit Can be Applied Against Production Taxes

A 20% investment tax credit also applies to moderate the impact of BPT, and this can be carried forward or traded (sold for use by other BPT-paying companies or purchased by the state in some cases) by eligible companies that are not yet generating sufficient revenues to pay BPT. In the initial year of investment only half the 20% capital investment credit can be used – in other words, if taken immediately, the credits must be spread over two years. Any remainder or all 20% can be applied in the next or any subsequent year.

Exploration Credits

Certain costs are allowed for exploration credits, provided that any data from the work associated with those costs is delivered to the Department of Natural Resources (DNR) and will eventually enter the public domain (e.g. after 2 years for well data and 10 years for seismic data). The type of activities that qualifies for such credits are:

- Investment in a new well (a) more than 3 miles from another well and (b) that DNR certifies as having an objective that is distinctly separate from one tested by a pre-existing well qualifies for a 30% exploration credit.
- Investment in a new well more than 25 miles from a unit boundary also qualifies for a 30% exploration credit.
- Well work that meets both of these conditions or acquisition of seismic data qualifies for a 40% exploration credit.
- There is also a 5% exploration credit allowed for seismic work performed before July 1, 2003, if commissioner of DNR determines that the work is "in the best interest of the state to acquire for public distribution".

Any cost used for an exploration credit cannot also be used for the 20% investment credit. However, costs used for exploration credits are generally also either deductible costs for calculating the PTV base for the year or the loss-carryforward credit of 25% available for use in the next or subsequent years.

These credits (investment and exploration) have a significant impact on project commerciality from a producer's perspective and continue to act as investment incentives and attract new entrants, particularly those engaged in exploration activities. Such instruments go some way to mitigating the high capital cost environment which characterizes oil and gas activities in Alaska. The impact of credits is such that some large projects are now commercially more sensitive to operating costs than capital costs. The credits are the most important existing counter to the regressive elements of royalty and property tax in the Alaska fiscal design.

Alaska Corporate Income Tax (CIT) Complexity

In this report, Alaska's CIT rate is approximated at a fixed 9.4% of income. This assumption leads to a simplistic combined federal income tax (FIT) and Alaska CIT approximate rate of 41.11%: a state rate of 9.4% and a federal rate of 35% on the same base, less a deduction for the state tax (9.4% + 35% *(1 - 0.094)). It is recognised that modelling from a specific company's perspective requires more detailed analysis. However, this approach is too simplistic to apply for detailed analysis and two quite distinct income tax bases need to be established for Alaska CIT and FIT (using different capital depreciation schemes and different methodologies).

Alaska, like many other states in the union is an ***apportionment state***. This means that for an income tax calculation a company's income from worldwide business activities, adjusted for taxes paid elsewhere and including income derived outside Alaska (i.e. oil and gas companies are on worldwide, not water's edge rules) is multiplied by Alaska's apportionment factor. Hence, for income tax analysis, information is required on certain components of income and production that each producer receives worldwide in addition to that derived from Alaska operations.

Alaska's apportionment factor is driven by the ratio of a taxpayer's Alaska property, production and sales to its worldwide property, production and sales. For most large IOCs the denominator (worldwide component) in that ratio is very large. This makes detailed modelling of Alaska CIT difficult and requires several company-specific inputs (assumptions) to compute it accurately. For generic modelling, such as that being conducted for this study some broad assumptions and approximations need to be made.

Depreciation of capital costs (both in Alaska and worldwide) for the Alaska CIT base applies the asset depreciation range (ADR) system (essentially straight-line over a range of years for different asset classes), which has been applied since 1980 in the Alaska tax code. Asset lives under the ADR system are typically longer than under than the current MACRS (modified accelerated cost recovery system) used for federal income tax (FIT) capital cost depreciation of Alaska assets. The model evaluated for this study applies a 7-year (average) ADR scheme for the Alaska CIT base and a 7-year MACRS scheme for the FIT base, the latter leading to more rapid depreciation of the asset values.

The Alaska CIT rate of 9.4% applies to all income above $90,000 using the following formula:

CIT = 9.4% x Alaska apportionment factor (AAF) x worldwide taxable income

Where worldwide taxable income = federal taxable income plus any taxes based on or measured by net income added back.

The AAF is calculated for upstream producers using three factors: 1) total sales ($), 2) plant value ($), and 3) oil and gas production (boe volume), each measuring a percentage of Alaska contributions to worldwide contributions. The three percentages are then summed and divided by three to provide the AAF. A worked example (Dickinson, 2008) illustrates the mechanism in Figure 3.1.5

Because of this broad taxation mechanism new entrants to Alaska typically incur a CIT liability years before they bring any discoveries into production. Prior to transporting any oil and/or gas in a pipeline or producing oil and/or gas, new entrants do not meet the oil and gas rules for producers and the three factors on which their AAF is calculated are plant, sales and payroll, with the latter replacing what would be a zero production factor. However, the plant factor does not include work in progress that has not yet been placed in service, so all three factors may be small relative to worldwide contributions. This is likely to be the case for major IOCs new to Alaska, but not always the case for smaller exploration and production independents.

International Oil Company A			
Figures in millions of dollars or barrel equivalents			
	Alaska	Everywhere	Ratio
Sales	250	25,000	1%
PPE	4,000	40,000	10%
Production	250	1,000	25%
Alaska Apportionment Factor			12%
Income (before Taxes)			2,500
Alaska Apportioned Income			300
Alaska Tax Rate			9.4%
Alaska Corporate Tax			28.2

Figure 3.1.5 illustration of how Alaska CIT might be calculated for an international oil company operating upstream in Alaska and at various other locations around the world (source: Dickinson, 2008). PPE in this figure refers to plant, property and equipment.

For generic modelling terms the Alaska CIT is therefore by necessity an approximation involving a number of assumptions.

Federal Income Tax and Credits

A 35% FIT rate is applied to remaining cash flow once Alaska CIT has been accounted for. This study applies that rate to the full residual income (after all other fiscal deductions) applying a 7-year MACRS depreciation scheme to capital costs. It is noted that the application of the 35% rate to the full FIT income base is a pessimistic assumption from the perspective of most large producing companies because there are many potential credits available, with a vast range of rules concerning eligibility that can be applied to reduce that income. Most available federal credits will have little to do with oil and gas operations in Alaska, are therefore difficult to model, predict or make general assumptions about, and need to be assessed on a company-by-company basis. This suggests that FIT liabilities modelled here are likely to be on the high side.

Outstanding Fiscal Issues Pertaining to Natural Gas

The current situation highlights the fact that there are many outstanding issues and uncertainties that need to be resolved prior to the sanctioning of a gas pipeline project and to provide a fiscal and commercial framework under which natural gas fields in Alaska can be developed and natural gas exploration can be encouraged. In addition to a revision of the overall fiscal design to make it more suited to natural gas developments some key uncertainties are:

- Should state equity participation be considered for midstream/downstream and upstream infrastructure projects?

- Should NGLs (including LPG) be subjected to the prevailing crude oil fiscal design or do they require alternative fiscal designs?
- How should upstream and midstream/downstream fiscal designs interact?
- Should infrastructure components such as gas processing plants be treated as upstream or midstream/downstream investments?
- What fiscal incentives, if any, are required to persuade producing companies to develop and explore for gas?
- How should the state's natural gas fiscal design treat associated natural gas in oil fields?
- How will environmental issues associated with carbon emissions and potential carbon capture and sequestration (CCS) be handled fiscally?
- Should there be tax incentives to encourage investment in the additional costs involved in CCS?

The quantitative fiscal modelling presented in this study does not address these issues mentioned in the bullet points above, but focuses on economic performance of the prevailing upstream fiscal design together with an evaluation focusing on alternative mechanisms for a gas progressivity tax making the overall fiscal design more progressive and flexible in response to both high and low prices and costs.

Gas and Oil Valuation Terminology Adopted in this Study for Quantitative Fiscal Analysis

Gas and Oil Valuation Terminology Adopted			
Alaska Net back Terminology	**Cost & Netback Components**	**Terminology Adopted for David Wood Report**	**Comments**
	Costs of refining and distributing refined products or dry gas	Refining and Marketing	(Considered as downstream of resource revenue cash flows)
"Revenue" - (even used when integrated IOC takes crude in to its own refining system)	Sale or Use (Price or Value) at Destination Market for crude oil or natural gas	Destination Value (sometimes expressed as a unit price)	Abbreviated to "DV" (would equate to "gross" revenue in some generic upstream gas and oil valuations)
Downstream Costs	Transportation and Tariff costs between Market and Point of Production (e.g. TAPS or other regulated pipelines and oil tankers) and gas Treatment plants. There is a property tax component included in these costs.	Transporation, Treatment and Tariff Costs	Abbreviated to "TT&T" ("Treatment" does not include field processing. Some may consider these components as "Midstream")
"Point of Production" or "Wellhead" divides Upstream from Downstream	Gross Value at Point of Production (also the point of royalty valuation)	Point of Production Value (sometimes expressed as a unit price)	Abbreviated to "PPV" (as this point may not be exactly at the "wellhead" that qualifier is avoided)
Upstream Costs (certain North Slope royalty agreements include "field costs" which cover some of these production cost components)	Exploration, Development and Production Facilities costs and property taxes on those assets (operating costs and capital costs)	Upstream Costs	Field processing costs are an upstream component - gas Treatment costs are a downstream component
	Production Tax Value - after subtraction of all allowable costs (i.e. the point of valuation for both basic and progressivity production tax)	Production Tax Value	Abbreviated to "PTV" (this equates to a "net" pre-tax cash flow value with all allowable costs, royalties and property taxes deducted)

Figure 3.1.6 Fiscal valuation terminology table compiled and agreed based upon discussions with the Alaska legislature (2008).

Worked Example for Single Period – Alaska Upstream Fiscal Calculation

Alaska Single Year Upstream Fiscal Calculation (2008)					Government Take	
Line Item Descriptions	**Inputs & Computations**	**Units**	**Producer Share**	**Costs**	**State* Share**	**Federal Share**
Destination Value (DV) Starts Producer Share						
Production	272	Million Barrels				
Value:	72.64	$/bbl				
Destination Value (Sales Revenue) (Price * Production)	19,753	Million Dollars	19,752.6			
Point of Production (PP)						
Subtract Downstream *Costs (DC) (Costs between Point of Production and Point of Sale) from DV						
Production	272	Million Barrels				
Per Unit Downstream Costs	6.34	Dollars/Bbls				
Downstream costs	1,724	Million Dollars	(1,724.0)	1,724.0		
*Portion of DS Costs that are AK property taxes				(105.0)	105.0	
DV From Above	19,753	Million Dollars				
DS Costs From Above	(1,724)	Million Dollars				
Yields Point of Production Value (PPV)	**18,029**	Million Dollars				
1. Royalty						
If Royalty in Value (RIV) calculate as set percentage of PPV (minus field costs in some fields)						
Value at Point of Production from above	18,029	Million Dollars				
Royalty Rate	12.5%	Percentage				
Subtract from PPV	2,254	Million Dollars				
Less Field Costs						
Result - Field Cost Deduction	10	Million Dollars				
Subtract from Producer Share and add to State Share	2,244	Million Dollars	(2,243.6)		2,243.6	
Production Tax Value (PTV)						
Calculate PTV as PPV without royalty, less qualified upstream capex and opex						
Production Tax Value (PPV less Royalty and Allowable Upstream Costs)						
PPV From Above	18,029	Million Dollars				
less Royalty Value (prior to field cost deduction) from above	(2,254)	Million Dollars				
Subtract Allowable *Opex from Non-Royalty PPV, total from Producer Share						
Upstream Opex Costs	(2,149)	Million Dollars	(2,149.0)	2,149.0		
Portion of US Costs that are AK Property Taxes				(52.5)	52.5	
Costs not allowed to be deducted			(107.5)	107.5		
Subtract Allowable *Capex From Non- Royalty PPV, total from Producer Share						
Upstream Capex Costs	(2,188)	Million Dollars	(2,188.0)	2,188.0	-	
Portion of US Costs that are AK Property Taxes				(52.5)	52.5	
30 cents a barrel exclusion			(71.4)	71.4		
Others Costs not allowed to be deducted			(109.4)	109.4		
Yields Production Tax Value (PTV)	**11,438**	Million Dollars				
***State and Local property taxes included in Downstream, Opex or Capex costs and local share is included in State Share.**						
Adjusted after Dickinson (2008)	*Page 1 of 2*			*David Wood & Associates*		

Figure 3.1.7 (Part 1) Alaska single-year upstream oil and gas producer fiscal calculation. Numbers highlighted in blue do not relate to any specific project and identifier user entry data required for this computation (source: D.E. Dickinson, 2008)

Alaska Single Year Upstream Fiscal Calculation (2008)

Line Item Descriptions	Inputs & Computations	Units	Producer Share	Costs	Government Take: State* Share	Government Take: Federal Share
2. Production Tax						
Calculate progressivity tax as % of PTV						
PTV From above	11,438	Million Dollars				
Taxable Barrels ((1-(royalty %)* total bbls)	238	Million Barrels				
Per Barrel Amount	48.07	$/bbl				
Progressivity Shield	30	$/bbl				
Subject to Progressivty	18.07	$/bbl				
.4%per dollar of PTV between $30 and $92.5	0.40%	percentage				
.1%per dollar of PTV between $92.5 and $342.5	0.10%	percentage				
Progressivity Percentage (4/10 or 1/10 per dollar)	7.2%	percentage				
Add progressivity to base tax as 25% of PTV	25.0%	percentage				
Total Production Tax Rate	32.2%	percentage				
Production Tax prior to credits	3,686.4	Million Dollars				
Check for floors, ceilings or private royalty taxes						
Apply Credits						
Less Investment Credits (1/2 prior year)	(200.00)	Million Dollars				
Less Investment Credits (1/2 current year)	(218.80)	Million Dollars				
Calculate total Production Tax	3,267.56	Million Dollars				
(If incremental must subtract tax without increment)						
Subtract from Producer Share and add to State Share			(3,267.6)		3,267.6	
3. Property Tax (State and Local) already moved from Producer to State Share (where an asterisked cost)						
Typically totals 2% of taxable property's value						
4. AK Corporate Income Tax						
Start with other World Wide Taxable Income, calculated using AK depreciation	120,000.00	Million Dollars				
Add Producer Share so far, with adjustment for treatment of Capex						
Plus Wellhead from Above	18,028.63	Million Dollars				
Less Royalty from Above	(2,243.58)	Million Dollars				
Less Production Tax from Above	(3,267.56)	Million Dollars				
Less Total Opex (Including Property Tax) from above	(2,256.45)	Million Dollars				
Less AK Depreciation from Capital Investment	(500.00)	Million Dollars				
Yields Pre Apportionment World Wide Income	129,761.04	Million Dollars				
Apply Alaska Apportionment Factor and 9.4% tax rate (and apply credits)						
Alaska Allocation Factor	0.05	percentage				
Alaska Taxable Income	6,488.05	Million Dollars				
Alaska Income Tax Rate	9.4%	percentage				
Yields AK Corporate Income Tax	609.88	Million Dollars				
(If incremental must subtract tax without increment)						
Subtract from Producer Share and add to State Share			(609.9)		609.9	
5. Federal Income Tax (FIT) (incremental)						
FIT (incremental) is Producer Share so far (With adjustment for Capex) multiplied by federal tax rate (35%)						
Wellhead from Above	18,028.63	Million Dollars				
Less Royalty from Above	(2,243.58)	Million Dollars				
Less Production Tax from Above	(3,267.56)	Million Dollars				
Less Total Opex (Including Property Tax) from above	(2,256.45)	Million Dollars				
Less Federal Depreciation from Capital Investment	(700.00)	Million Dollars				
Less State Income Tax from Above	(609.88)	Million Dollars				
Income Subject to Federal Taxation	8,951.16	Million Dollars				
Federal Tax Rate	35.0%	percentage				
Subtract from producer share and add to federal share	3,132.91	Million Dollars	(3,132.9)			3,132.9
Total Shares						
Totals:	19,752.63	19,752.6	4,149.5	6,139.2	6,331.0	3,132.9
Shares in Percentage						
% of Total Revenue	100%	19,753	21%	31%	32%	16%
% of Total Revenue less Costs = Cash Flow	100%	13,613	30%		47%	23%
Total Government share of Cash Flow =69.5 %						

Adjusted after Dickinson (2008) *Page 2 of 2* *David Wood & Associates*

Figure 3.1.7 (Part 2) Alaska single-year upstream oil and gas producer fiscal calculation Numbers highlighted in blue do not relate to any specific project and identifier user entry data required for this computation (source: D.E. Dickinson, 2008)