Technical Royalty Report OS#1: Alberta's Oil Sands Fiscal System - Historical Context and System Performance -

This report is a technical report by the Alberta Department of Energy (ADOE). This is the first in a series of technical reports to contribute to the public understanding of oil and gas royalty issues.

Section I - Introduction:
This report is the first of a series of technical reports describing the fiscal system applied to Alberta's oil sands.[1] The purpose of the series is to provide information and to invite comment as part of the Government of Alberta's public review of the fiscal system applied to the province's oil and gas resources. Other reports will provide information on conventional oil and natural gas.

The purpose of this report – Technical Report OS#1 - is to assess the robustness[2] of Alberta's oil sands fiscal system and to assess how the regime balances the risks and rewards to both investors and the resource owner (Albertans) across a range of expected and probable economic outcomes.

The objective is not to show if a given project is economically viable under a particular set of price, production, and cost conditions; rather, it is to recognize that predicting future economics is inherently uncertain, particularly for the global petroleum industry of which Alberta is an integral part. Therefore, the criteria against which a petroleum fiscal system is judged "good" or "bad' is not the share of revenue captured as economic rent[3] for a given project, or set of projects, at a particular point in time; it is how well this share reflects risks and rewards over a range of anticipated prices, production levels, and costs, any one of which is impossible to predict with any degree of precision. Notwithstanding the associated difficulties in designing a royalty system, it is nevertheless necessary to define a reasonable planning range for relevant economic variables and ensure that the revenue captured across this range is consistent with the regime's objectives.

[1] The term 'fiscal system' refers to the combination of royalties, taxes, bonuses, and land rental fees applied to a given production activity. For Alberta, the fiscal system is a combination of bonus payments through auction, royalties, land rental fees, and both federal and provincial corporate income taxes. Municipal taxes and other levies such as personal income taxes are included in project costs and are therefore not included in this definition.

[2] Robustness refers to how well the fiscal system delivers the intended and expected benefits under a variety of economic conditions.

[3] Economic Rent is *the price that the owner of a non-renewable resource would charge for the use of this resource*, assuming efficient markets. Costs, risks, and competitiveness are considerations that the resource owner takes into account in determining this price. In technical terms, economic rent is the return to a factor of production that is above that which is sufficient to bring the factor into productive use. This is sometimes referred to as economic profits. Stated yet another way, economic rent is the income remaining after the investor has recovered all project costs, accounted for risk, and achieved a competitive rate of return on investment. Costs include land purchases (bonus payments), unsuccessful exploration, drilling, plant and facilities, and transportation. Typical risks (positive and negative) include pool sizes that turn out to be smaller or larger than expected, cost overruns and savings, price changes - both upward and downward, changes in exchange rates, and also, the risk that the fiscal system will be changed. Competitive jurisdictions have comparable combinations of resource and market characteristics, including market access and political risk.

While this report sheds light on the robustness of the fiscal system, its scope does not permit a conclusion with respect to fair share[4] or whether the current regime captures the economic rent. Fair share and economic rent are integrally related and fair share cannot be determined without considering economic rent; however, neither can be fully assessed without considering competitiveness and the investment alternatives in competing jurisdictions. Competitiveness and fair share will be the subjects of other reports in this series.

This report is divided into six sections. Section II – History and Context provides a brief description of the historical context to the current oil sands fiscal system. Section III provides a description of the system, illustrating its important components and their interrelationship. Section IV describes the methodology used for the analysis presented in Sections V and VI. Section VII provides summary observations and sets the stage for the second report.

Section II – History and Context

The current generic royalty regime applied to Alberta's oil sands resources – the Oil Sands Royalty Regulation, 1997 ("the OSRR97") - was enacted in 1997. Prior to that time, individual Crown Agreements establishing royalty terms had been separately negotiated with oil sands project developers. This produced a case-by-case approach to fiscal system design and application. A brief summary of the Crown Agreements in force prior to the adoption of the generic regime follows:[5]

<u>Suncor (Mining and Upgrading):</u>

In 1987, Suncor moved to a net revenue royalty system. Royalties were calculated as the greater of 30% of net revenues or 5% of gross production. Allowed capital and operating costs were grossed up by 1% and 10% respectively, to determine net revenues.[6] In any year when the minimum gross royalty exceeded the net royalties calculated, the difference was carried forward to future years - as a deduction against royalty payable when the net royalty became greater than the gross royalty.

<u>Syncrude (Mining and Upgrading):</u>

Syncrude paid 50% of the project's net profit (net revenue) to Alberta as royalty. It did not have a minimum royalty on gross production. Therefore, in any year when the net royalty calculated was negative, no royalties were paid.

<u>Cold Lake Regime (In-Situ Thermal):</u>

Typically, the royalty terms applicable to commercial in situ projects prior to the announcement of the new generic royalty system were based upon the royalty terms provided to Imperial Oil's Cold Lake project. This royalty consisted of a 1% royalty on gross revenue at start-up, increasing by 1% every 18 months to a maximum of 5%. The royalty then remained at 5% of gross

[4] "What is fair share is inherently a subjective concept. At best, it is a value judgment or opinion that can neither be refuted nor proven"; Wade Locke, *Is Newfoundland and Labrador Getting its Fair Share*, Newfoundland Quarterly, Vol. 99, No. 3, 2007. While the definition of Fair Share can include royalties and taxes as well as other considerations such as investment activity and employment, it is most common around the world for the oil and gas industry and in the economics literature to define a jurisdiction's fair share as the sum of royalties, corporate income taxes, bonuses, and land rental fees. Even with this definition, there is an implicit assumption of a level of investment and sector activity sufficient for a healthy industry, and a healthy economy.

[5] After Mason, Richard and Bryan Remillard, *Alberta's New Oil Sands Royalty System*, Alberta Dept. of Energy, May, 1996.

[6] The 1% and 10% gross-up factors were applied for ease of administration in accounting for costs such head office management and insurance that are difficult to allocate to a specific project.

production until payout (when gross revenue exceeded cumulative operating costs, capital costs, gross royalty, and a 10% return allowance on unrecovered costs). At this point the royalty converted to the greater of 30% of net revenues or 5% of gross production. Capital and operating costs were grossed up by 1% and 10% respectively, in the calculation of net revenue.

A case-by-case approach reflected the development of the understanding of a new resource. This approach was manageable with a small number of commercial projects. However it did not provide certainty about royalty treatment for future projects or a level playing field across all projects. It was also administratively complex, both in negotiating and administering unique sets of fiscal terms.

The National Task Force on Oil Sands Strategies was formed by the Alberta Chamber of Resources in 1993. This committee consisted of representatives from the oil sands sector and supporting industries, as well as representatives from both the provincial and federal governments.

The Task Force report was published in 1995 under the title *The Oil Sands: A New Energy Vision for Canada*. The report included six (6) appendices; the most important for the current assessment being *Appendix C: Fiscal Report – A Recommended Fiscal Regime for Canada's Oil Sands Industry*.

At the time, Alberta's oil sands were considered an "infant"[7] industry. Special fiscal terms were proposed to "catalyze accelerated development." The Task Force "… concluded that, at oil prices in the range of CAD $25.00, the Canadian oil sands industry can grow to reach sales of 800,000 to 1.2 million barrels per day of crude oil and bitumen in the next quarter century [by 2020] … with a direct investment of $20 to $25 billion."

The Fiscal Report identified its broad objective as the recommendation of a set of fiscal terms that will:

- Maximize the growth of the oil sands contribution to gross domestic product
- Encourage industry efficiency
- Provide fiscal stability and avoid the need for ad hoc adjustments or "one-off" project arrangements of subsidies
- Provide a fiscal structure such that economic growth objectives can be accomplished while returning an equitable share of economic rent to governments.

To these ends, the Task Force proposed a generic oil sands royalty system, based on a set percentage of net project revenues after all costs were recovered. This type of "resource rent royalty" approach was not new to the oil sands sector: as noted above, all existing oil sands projects with Crown royalty agreements had some form of a net revenue royalty.[8] Alberta's experience with net revenue royalty agreements, and the Task Force's recommendations, provided the basis for the new generic royalty system.

Section III – Oil Sands Fiscal System Description

The Fiscal Report considered a number of tax-royalty combinations to reflect the Task Force objectives. For example, accelerated capital cost write-offs, immediate write-offs, no gross royalty[9], gross royalty

[7] Economics recognizes the "infant" industry argument that new or fledgling industries may justify special fiscal or trade provisions in order to become established.

[8] The resource rent royalty system is applied in many other jurisdictions around the world; e.g., Canada, in the North, Newfoundland and Labrador and Nova Scotia on Canada's East coast, and Commonwealth Lands in Australia.

[9] The task force had recommended that there be no gross royalty. From a theoretical perspective a zero gross royalty works best; however, when one considers other issues such as the balancing of risks between resource owners and investors it is common around the world to apply a gross royalty that is typically in the range of 5% - 15%. For example: in addition to

increasing from 1% to 5% after six years, net royalty rates of 20% to 30%, and reduced rates for Federal corporate income tax.

The Task Force concluded that "… the retention of a combined tax and royalty rate in the range of 60% is reasonable" and that the recommended terms were fair and robust under a wide range of circumstances including price volatility, changes in inflation rates, as well as differences in project size and scope.

The fiscal terms ultimately adopted by Governments are representative of those recommended by the Task Force. The terms are summarized here as:

Royalty:

- 1% of gross revenue until project payout; and,
- 25% of net revenue, after payout. The royalty is the greater of the gross and net values.
- Gross revenue is determined by the product of production and price adjusted to transportation costs.
- Net revenue is defined as gross revenue less qualifying investments and operating costs.
- Payout occurs when all project costs, plus an allowance for rate of return equal to the Government of Canada long term bond rate (e.g., 4% - 6%), have been recovered.

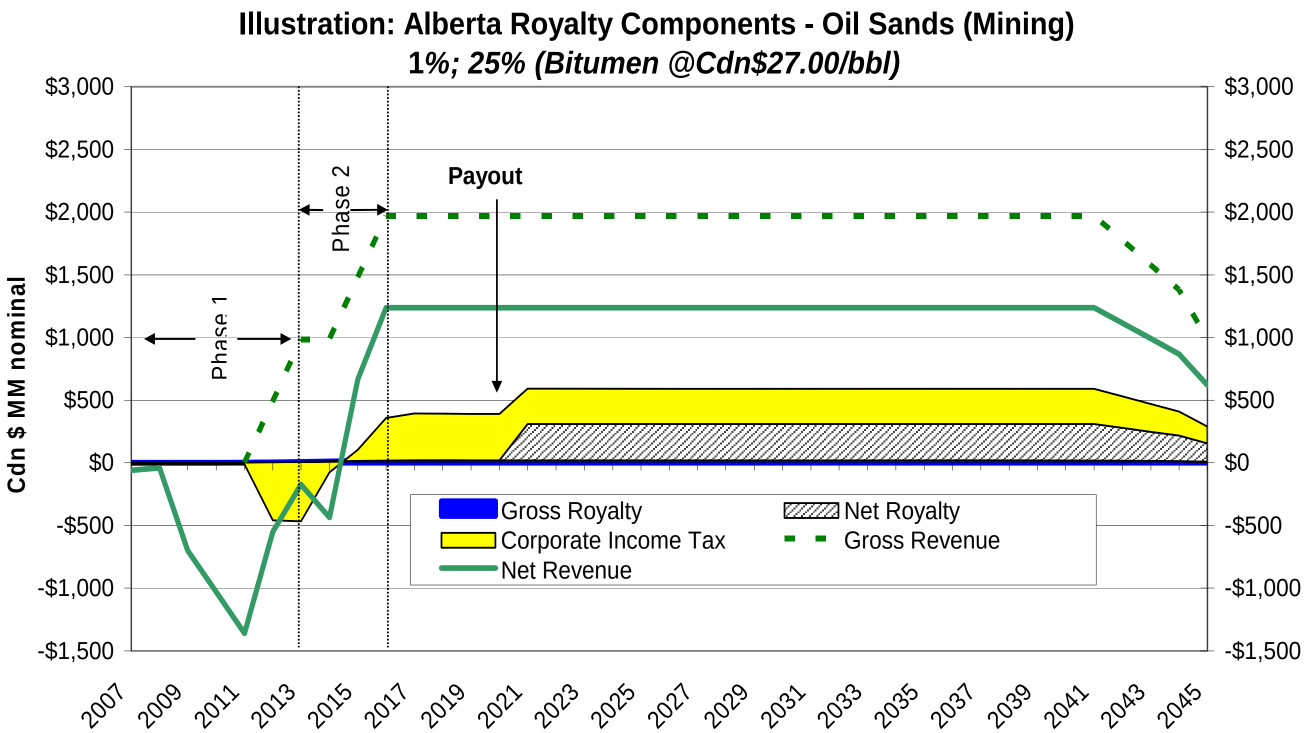
Corporate Income Tax:

- Normal rules apply however capital costs attributed to project expansion qualify for immediate write-off. This is referred to as Accelerated Capital Cost Allowance or ACCA.[10]
- ACCA is subject to certain conditions. The most noteworthy being: (a) the costs must be for the purpose of expanding production and not just for plant maintenance and (b) the ACCA is "ring fenced" meaning it can only be claimed against the income of the project and not that of the entire corporation.
- The CIT rates were not prescribed. Rates at the time were: Federal 29.12% (28% plus a surtax of 4% of the 28%) and Alberta 14.50%, for a combined rate of 43.62%. Royalties were not deductible in determining taxable income however the Resource Allowance was allowed as a proxy. Resource Allowance has subsequently been phased out with royalties now fully deductible as of 2007. Current CIT rates are Federal 20% and Alberta 10%, for a combined rate of 30%.

The following chart illustrates the relationship between corporate income tax and royalties for a representative oil sands project. The chart shows royalties and taxes in the context of gross and net project revenues. The dashed line shows gross revenue (the product of production and price at the project boundary) while the solid green line illustrates net revenue (gross revenue less investments, and operating costs). The yellow section shows corporate income tax – first the benefits for the investor from tax write-offs (the yellow area below the zero line) and then the benefits to governments as costs are recovered and taxable income turns positive. The 25% net profits royalty is illustrated by the grey hatched area beginning with payout. The gross royalty (blue area) is next to the zero-line and is paid from the beginning of first production. Gross royalty is difficult to discern in the chart as its value is relatively small when compared to the values for CIT and net royalty.

corporate income tax and property tax, Alaska's new Petroleum Profits Tax incorporates a 22.5% profit share and a 12.5% royalty.

[10] The recent Federal Budget announced changes to the ACCA rules that see this feature phased out for new projects by 2015.



Section IV – Methodology

The methodology employed for the analysis of the oil sands fiscal system was to construct ranges of cases representing possible economic outcomes. This methodology has two components:

The first follows the traditional approach of constructing "Low" to "High" economic scenarios and to assess the economics of each scenario. To better test system robustness, this range was supplemented at each end by "Low-Low" and "High-High" cases to produce five scenarios for both the in-situ SAGD [11] and Mining extraction technologies. Integrated cases involving the upgrading of raw bitumen to higher valued products such as synthetic crude oil (SCO) are assessed for the mining operations. Integrated SAGD operations are not assessed here however they will be discussed in a separate report.

The second methodological approach was incorporated to reflect the inherent limitations of the traditional scenario approach; i.e., debate over assumptions, and to better account for the extreme level of change currently being experienced by the world petroleum industry, particularly as it relates to prices and costs.

Because of the relatively high level of investment activity and the rapid expansion of bitumen production, the current level of cost and price uncertainty may be even more pronounced in Alberta. For these reasons, the traditional scenario approach is extended by constructing a "fiscal map"[12] of price and cost combinations. This increases the number of potential outcomes for consideration and helps avoid conflicts that often arise among analysts over the selection of parameters as representative for specific

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[11] SAGD – Steam Assisted Gravity Drainage.

[12] The fiscal map is approach is also followed by world petroleum fiscal systems expert Dr. A Pedro H. van Meurs. The map is a presentation of economic decision-making criteria; e.g., rate of return or net present value, that result from the combination of two or more economic variables; e.g., price and costs. The fiscal map facilitates consideration of a wider range of possible outcomes than the traditional scenario approach.

scenarios. The fiscal map approach better recognizes that the cut-off between economic and non-economic projects is not represented by a hard-and-fast line; rather, for any given production level, it is a continuum of cost and price combinations. This approach is more useful for fiscal system analysis as the objective is not so much the determination of a particular economic outcome as it is to provide for the full range of expectations.

The methodology for the economics and fiscal system analysis is to compare a variety of commonly used investment decision-making criteria; e.g., net present value (NPV)[13], NPV/boe[14], internal rate of return[15], and government share[16].

Section V – Economics and Fiscal System Analysis – Scenario Approach

Tables 1 and 2 provide the assumptions for the five scenario cases. The capital costs are derived from a combination of consultant reports and recent publicly available company information. From these sources representative extremes from recent projects were selected to represent the low and high values with the medium value being the average of the extremes.

A similar approach was followed for operating costs with the SAGD cases reflecting a range of energy requirements through the steam-oil-ratio (SOR). Medium case natural gas costs are based on a natural gas price of CAD $6.75/Mcf with the other cases reflecting gas prices that track the price of crude oil within the price range assumed.

Scenario prices are based on experts' predictions that see the price for light crude oil in the most likely range of U.S. $45.00 to $55.00 per barrel. Adjustments are then made for quality[17], transportation[18], and USA-Canada currency exchange from 0.85 to 0.90 to determine a plant-gate bitumen price. The resultant values were found to be comparable when checked against company reports and other information available to the Department of Energy. The synthetic crude oil (SCO) price for the integrated analysis was assumed to be in the range of 92% - 99% of the WTI price.

Table 3 – Cost Comparisons – provides some further context for the capital and operating cost estimates by comparing them with costs from other recent published sources. ADOE has determined that there is significant inconsistency in the methodology employed across the range of cost estimates quoted by industry commentators and indeed by individual companies. For example: some sources quote nominal

[13] Net present value (NPV) is a way of comparing a stream of revenues and expenditures over time so as to acknowledge that money today has a higher value than money in the future. Since money today can be invested and earn a rate of return, it has a higher value than the same amount some time into the future. To account for the return that alternative investment opportunities can earn it is common to discount the expected revenues and costs. The rate of discount is typically 10% real (NPV_{10}). See footnote 19.

[14] NPV/boe is the net present value per barrel of oil equivalent (boe).

[15] Internal rate of return (IROR) is a measure similar to NPV; however, it shows the rate that future revenues and costs would need to be discounted by to achieve a NPV of zero. This measure is useful as it readily facilitates comparison with other projects and across economic sectors.

[16] Government share is the percentage of project revenues that are paid to governments once capital, operating, and transportation costs have been deducted.

[17] Quality adjustment is made for crude density as reflected in the American Petroleum Institute (API) measure for gravity, the percent sulphur in the crude and the crude's acidity as reflected in the total acid number (TAN). Adjustments are made for both Cold Lake-area and Athabasca-area bitumen in relation to West Texas Intermediate (WTI) at Cushing Oklahoma.

[18] Transportation costs reflect those from Oklahoma to the assumed point of sale in the Chicago area and then from the point of sale back to the plant gate in Alberta.

dollars while others use real or constant dollars; some are in 2005 dollars and other in 2007 dollars;[19] some include transportation as a component of operating costs while others provide a corresponding reduction in price; other examples see differing allocations of costs between mining and extraction and upgrading for integrated projects. After accounting for such inconsistencies, the costs employed for this analysis are comparable with recent estimates from other sources.

It is highlighted that there is considerable uncertainty around costs, particularly whether or not current high cost conditions reflect a short term phenomena. Some commentators suggest that costs are high because prices are high. Specifically, it is argued that costs are high because contractors believe that higher oil prices means that oil companies can afford to pay more. Others explanations point to world-wide economic growth causing higher costs for commodities such as steel and shortages of experienced labour such as engineering and management expertise. Still others suggest that current cost estimates reflect caution on the part of investors who include high contingencies in their estimates. Finally, in the case of Alberta, a pace of development that is faster than the economy can readily accommodate is also added to the list of causes.

Although it is likely that the cost increases being experienced result from a combination of causes, the important issue for the present report is that the fiscal system needs to be robust enough to reflect the realities of the market. Separate technical reports are being prepared on pricing and costs. These will serve as appendices to the present report.

Tables 4a and 4b present a summary of the scenario analysis results. Highlights from Table 4a are:

- While there is a wide range of project outcomes across all oil sands areas the Cold Lake area, SAGD projects are shown to have more robust economics than similar projects in the Athabasca area. This is due to Athabasca area projects being relatively disadvantaged by higher transportation costs and a lower quality resource. This is reflected in an Athabasca price differential for this analysis of $4/bbl to $8/bbl when compared to the Cold Lake scenarios.
- All scenarios are shown to have attractive economics, with significant upside potential. The IROR for the Cold Lake scenarios has a range of 15.7% to 42.2%. The range for the Athabasca scenarios is 10.9% to 35.0%.
- The recorded NPV_{10} values (see footnote 13) are highlighted as this profitability measure is particularly illustrative of the investment attractiveness of the oil sands. These values reflect representative projects with recoverable reserves of 600 million and 2,200 million barrels for SAGD and Mining, respectively.
- These recoverable reserves values can be compared, for example, to those for Alaska where a representative field might be 50 – 100 million barrels and the chance of success is in the order of one in four or one in five exploration wells drilled. Oil sands projects offer the investor a long term stable source of cash flow and crude oil supply.
- Low bitumen prices may be cause for concern if current cost conditions continue, particularly for the Athabasca area projects.

Table 4b compares the Athabasca mining/extraction and integrated projects. As with the SAGD comparisons, the economics for mining/extraction and integrated upgrading are shown to be attractive over the full range of scenarios, with some concern in the extreme low price-high cost scenario. Of particular interest in this comparison is the high value creation opportunity afforded by integrated

[19] Nominal dollars refers to expenditures or revenues that include inflation over time. Real dollars have the inflationary component removed and can be denominated in terms of the purchasing power for any given year; e.g., 2005 or 2007. The inflation rate assumed for this analysis is 2% per annum.

upgrading. For example, the NPV almost doubles from the mining/extraction to the integrated mining case – for the assumed 200,000 barrel per day operation the NPV_{10} increases from $769 million to $1,614 million. Similarly, NPV_{10} per barrel increases from $0.34 to $0.84.

Fiscal system robustness is assessed by considering the government share of net revenue (see footnote 16), and the investor IROR and NPV for the various cases:

- Table 4a shows the government share (undiscounted) to be consistently in the order of 47%. This follows directly from the nature of the oil sands fiscal regime.[20]
- The investor's share as measured by rate of return and NPV_{10}/boe is shown to increase substantially from the low cases to the high profitability cases. The rate of return across the Mining and SAGD cases ranges from 9.0% to 42.2%.
- The performance of rate of return can be contrasted with that of the discounted government share. On a discounted basis government share for the Athabasca SAGD case actually declines from about 59% in Low-Low scenario to 48% for the high profitability scenario. Similar results are reflected in the Cold Lake SAGD and Athabasca Mining cases.

Section VI – Economics and Fiscal System Analysis – Fiscal Map Approach

The scenario methodology for assessing project economics and fiscal system performance can be enhanced by extending the range of possible outcomes. The intent is to move away from attempting to define a "most likely" or base case to constructing a comprehensive set of cases – the Fiscal Map - to capture not only the expected outcomes, but also those outcomes that may not be expected but nevertheless ought to be considered. This approach is particularly important for governments that need to design fiscal systems to accommodate a range of investment conditions that is even wider than those faced by a particular investor at any given point in time.

Tables 5.1a to 5.4e present fiscal maps for a broad range of price and cost combinations for four representative projects: Cold Lake SAGD, Athabasca SAGD, Athabasca Mining, and Athabasca Integrated Mining and Upgrading. All projects are assessed for prices representing a range for WTI from U.S. $20 to $120 per barrel. These cases are then combined with six cost levels representing the cost extremes identified in Table 3.

Tables 5.1a to 5.1e present the Cold Lake SAGD analysis results for IROR, NPV_{10}/boe, NPV_{10}, and Government Share in nominal dollar terms (inflation included) and in real terms (inflation removed) discounted at 5%. Results for the other projects are presented in the table series 5.2, 5.3, and 5.4.

The fiscal maps show the same general picture for all four project-types assessed. Only the Athabasca mining project is selected for discussion. While the mining project results are shown to be somewhat less attractive on a non-integrated basis than those for the SAGD projects, the broad conclusions are the same. Selecting the mining case better facilitates comparison with the integrated case.

Table 5.3a: Athabasca Mine shows the investor IROR to be attractive for prices above U.S. $40/bbl, even under current high cost conditions. Tables 5.1a and 5.2a show somewhat more attractive economics for both the Athabasca and Cold Lake area SAGD cases.

[20] A combined Federal and Alberta tax rate of 30% plus a 25% royalty share that is deductible in determining taxable income yields a marginal rate of (100% - 25%) x 30% + 25% = 47.50%.

Table 5.3a shows that recent prices in the order of U.S. $50 to $60/bbl see Athabasca mining IRORs ranging from about 12% to 27%. In fact, most cost levels see positive economics at the $40/bbl price level and above. Higher prices and lower costs could see rates exceed 45%.

In the context of the royalty review, it is particularly interesting to compare the measures of project profitability with the government share. While the discounted government share table offers useful insights, it is most common around the world to compare government shares in nominal dollars.

Table 5.3b: Athabasca Mine Government Share clearly shows the current oil sands system to be not responsive as project profitability outcomes improve. As was shown with the scenario analysis above, the government share is basically 47% across all economic outcomes.

Tables 5.4a to 5.4e show the economics for the integrated mining case. Two observations are highlighted from these tables: (1) the government share declines to 40% [21] for the integrated cases and (2) integrated operations represent significant value creation for the investor. This can be seen by comparing the $\mathbf{NPV_{10}}$ results for the mining project (Table 3.d) with those for the mine-with-upgrader project (Table 4.d). These results confirm those shown above in the scenario analysis, demonstrating that the NPV for the integrated projects is practically double that for just the mine alone.

Some argue that the share is too high under low prices with high costs, while resource owners argue that the government share should be higher for extremely profitable situations; e.g., high prices.

Alberta's royalty share under the oil sands system is 1% until costs have been recovered.[22] This aspect of the system in unlikely to cause otherwise economically viable projects to become uneconomic. Unattractive economics for lower prices or higher costs would reflect inherently poor investment conditions and not the structure of the current fiscal regime.

Further analysis of the performance of the oil sands fiscal system will be included in Technical Report OS#2 of this series. Following this, Technical Report OS#3 will provide useful context by comparing the oil sands fiscal system and investment attractiveness with oil and gas investment opportunities in competing comparable jurisdictions such as Alaska, Norway, and Venezuela. These reports are expected to be available by late April and mid-May, respectively.

Section VII – Summary Observations

The oil sands fiscal system is very flexible for adverse economic conditions and very much less so for highly profitable conditions.

Before any changes in the fiscal system can be designed, it is necessary to determine the level of government share that the cost, price, and production characteristics of Alberta's oil sands can support and still maintain a healthy sector and economy. In other words, it is first necessary to determine the competitiveness of Alberta's resources. This will be the subject of Technical Report OS#2 – Oil Sands Fiscal System Performance, and Technical Report OS#3 – Oil Sands Competitiveness Assessment. Report OS#2 will be an extension of the present report offering a broader discussion of issues including

[21] The decline in government share from 47% to 40% in the integrated mining case results from the application of only the 30% corporate income tax to the upgrader portion of the project revenues.

[22] The corporate income tax rate of 30% applies only after taxable income becomes positive. In fact, prior to this point a corporation may benefit from tax write-offs. Similarly the 25% royalty net profit share only applies when costs have been recovered and a rate of return on investment has been achieved.

bitumen valuation and upgrading economics. Report OS#3 will compare the investment economics and fiscal systems in competing jurisdictions; e.g., Alaska, Norway, and Venezuela, and identify options for improving the oil sand fiscal system.

Table 1: Scenario Assumptions											
Cold Lake and Athabasca SAGD Extraction											
		Cold Lake SAGD					**Athabasca SAGD**				
		Low-Low	Low	Medium	High	High-High	Low-Low	Low	Medium	High	High-High
Exch. Rate	0.88										
Athabasca Differential[1]	45.00%										
Cold Lake Differential[1]	55.00%										
Steam-Oil Ratio		2.50	3.50	2.50	2.00	2.00	2.50	3.50	2.50	2.00	2.00
Production	bopd	60,000	60,000	60,000	200,000	200,000	60,000	60,000	60,000	200,000	200,000
Price											
WTI (Chicago)	$USA/Bbl	35	50	50	50	67	35	50	50	50	67
Bitumen (Alb)	$USA/Bbl	19	28	28	28	37	16	23	23	23	30
Bitumen (Alb)	$Cdn/Bbl	22	31	31	31	42	18	26	26	26	34
Initial Capex	$/bpd peak	19,000	25,000	19,000	12,000	12,000	19,000	25,000	19,000	12,000	12,000
Total Capex	$/Bbl	3.94	4.57	3.94	2.07	2.07	3.94	4.57	3.94	2.07	2.07
Opex	$/Bbl	8.85	13.54	10.87	8.34	9.96	8.85	13.54	10.87	8.34	9.96

Legend:
Medium = (Low + High) / 2
Low & High based on Wood Mackenzie: *Upstream Insights*, Jan., 2007 and company public information
High-High = High @ Gas and Bitumen Price = +30%
Low-Low = Med @ Gas and Bitumen Price = -30%
1. Differential to West Texas Intermediate (WTI)

Source: ADOE, Apr. 12, 2007

Table 2: Scenario Assumptions											
Athabasca Mining & Extraction and Upgrading											
		Mining					**Integrated**				
		Low-Low	Low	Medium	High	High-High	Low-Low	Low	Medium	High	High-High
Exch. Rate	0.88										
Bitumen Differential[1]	45.00%										
SCO Differential[1]	95.00%										
Production	bopd	200,000	200,000	200,000	450,000	450,000	170,000	170,000	170,000	382,500	382,500
Price											
WTI (Chicago)	$USA/Bbl	35	50	50	50	67	35	50	50	50	67
SCO (Alb)	$USA/Bbl	33	48	48	48	64	33	48	48	48	64
SCO (Alb)	$Cdn/Bbl	38	54	54	54	72	38	54	54	54	72
Bitumen (Alb)	$USA/Bbl	16	23	23	23	30	16	23	23	23	30
Bitumen (Alb)	$Cdn/Bbl	18	26	26	26	34	18	26	26	26	34
Initial Capex	$/bpd peak	28,600	34,650	28,600	22,550	22,550	52,000	63,000	52,000	41,000	41,000
Total Capex	$/Bbl	3.57	4.11	3.57	3.00	3.00	7.74	8.89	7.74	6.57	6.57
Opex	$/Bbl	8.53	10.02	9.03	8.04	8.54	19.16	22.38	19.16	15.94	15.93

Legend:
Medium = (Low + High) / 2
Low & High based on Wood Mackenzie: *Upstream Insights*, Jan., 2007 and company public information
High-High = High @ Gas and Bitumen Price = +30%
Low-Low = Med @ Gas and Bitumen Price = -30%
1. Differential to West Texas Intermediate (WTI)

Source: ADOE, Apr. 12, 2007

Table 3: Oil Sands Costs
Alberta Energy Summary and Third-Party Sources
($ CAD 2007)

	Capital		Operating		Total
			Energy	Non-Energy	Operating
	$/peak barrel*	$/barrel	($/barrel [1])	($/barrel)	($/barrel)
Alberta Energy					
SAGD	19,000 [2]	3.94	7.46	3.41	10.87
Mining	28,600 [3]	3.57	2.45	6.58	9.03
Integrated Mining	52,000 [4]	6.93	6.20	10.08	16.28
Strategy West					
SAGD	25,000		8.00	4.00	12.00
Mining	35,000		1.35	8.00	9.35
Integrated Mining	77,500		6.06	20.00	26.08
CERI					
SAGD	20,000	3.95	7.71	2.50	10.21
Mining	20,000 [5]	2.43	2.71	6.32	9.03
Integrated Mining	55,000 [6]	6.63	6.15	8.37	14.52
TD Bank					
SAGD	22,363				
Mining	33,587				
Integrated Mining	73,520				
National Energy Board					
SAGD	15,000		8.50	3.50	12.00
Mining	20,000				10.50
Integrated Mining	52,000		8.00	12.00	20.00

Cost Assumptions for the Fiscal Map Sensitivities

	Level 6	Level 5	Level 4	Level 3	Level 2	Level 1
Cold Lake - SAGD						
CapEx/Peak bbl (Bit.)	$25,650	$22,800	$19,000	$15,200	$13,300	$11,400
% Change	35%	20%	-	-20%	-30%	-40%
Total Costs/bbl	$17.61	$16.41	$14.81	$13.21	$12.41	$11.61
Athabasca - SAGD						
CapEx/Peak bbl (Bit.)	$25,650	$22,800	$19,000	$15,200	$13,300	$11,400
% Change	35%	20%	-	-20%	-30%	-40%
Total Costs/bbl	$17.61	$16.41	$14.81	$13.21	$12.41	$11.61
Athabasca Mining						
CapEx/Peak bbl (Bit.)	$35,750	$32,890	$28,600	$25,740	$21,450	$18,590
% Change	25%	15%	-	-10%	-25%	-35%
Total Costs/bbl	$15.33	$14.24	$12.60	$11.51	$9.87	$8.78
Athabasca Mining Integrated						
CapEx/Peak bbl (SCO)	$92,647	$85,235	$74,118	$66,706	$55,588	$48,176
% Change	25%	15%	-	-10%	-25%	-35%
Total Costs/bbl	$33.61	$31.38	$28.05	$25.82	$22.48	$20.26

* All barrels represented on this table are barrels of Bitumen. 1. Assumes Gas Price at $ CAD 6.74/Mcf
2. Range from 12,000 to 25,000. 3. Range from 22,550 to 34,650. 4. Based on industry reports of a range from 41,000 to 63,000.
5. Range from 12,000 to 31,000. 6. Range from 40,000 to 128,000.

Source: Alberta Energy, Feb., 2007

Table 4a: Scenario Analysis Results

Oil Sands Extraction Economics - Cold Lake and Athabasca SAGD

		Cold Lake SAGD					Athabasca SAGD				
		Low-Low	Low	Medium	High	High-High	Low-Low	Low	Medium	High	High-High
IROR	%	15.69%	16.08%	22.39%	33.67%	42.24%	10.92%	11.79%	17.75%	28.33%	35.01%
NPV10	MM$	189.63	288.71	622.39	3414.91	5314.50	-63.37	-27.98	313.29	2393.44	3692.55
NPV10/$Inv	$	0.19	0.24	0.63	1.80	2.80	-0.06	-0.02	0.32	1.26	1.94
NPV10/boe	$/Bbl	0.33	0.51	1.09	1.80	2.80	-0.11	-0.05	0.55	1.26	1.95
Gov.% NPV5	%	52%	52%	50%	48%	48%	59%	56%	51%	49%	48%
Gov.% Nominal	%	47%	47%	47%	47%	48%	46%	47%	47%	47%	47%

Source: ADOE, Apr. 12, 2007

Table 4b: Scenario Analysis Results

Oil Sands Extraction Economics - Athabasca Mining, Extraction and Upgrading

		Mining					Integrated				
		Low-Low	Low	Medium	High	High-High	Low-Low	Low	Medium	High	High-High
IROR	%	9.00%	12.32%	14.90%	19.19%	25.01%	8.78%	12.08%	15.26%	20.19%	27.19%
NPV10	MM$	-817.38	39.2	768.8	3151.56	6199.97	-1580.27	-69.99	1614.48	6807.57	13923.55
NPV10/$Inv	$	-0.21	0.01	0.19	0.51	1.01	-0.22	-0.01	0.23	0.61	1.25
NPV10/boe	$/Bbl	-0.36	0.02	0.34	0.64	1.27	-0.82	-0.04	0.84	1.64	3.35
Gov.% NPV5	%	64%	54%	52%	50%	49%	60%	48%	44%	42%	41%
Gov.% Nominal	%	46%	47%	47%	47%	48%	39%	40%	40%	40%	40%

Source: ADOE, Apr. 12, 2007

Fiscal Maps
- Color Code -

Color Code (Investor Perspective)		Real IROR
Red	Stop	< 10%
Green	Average	10% - 15%
Blue	High	> 15%
Yellow	Very High	> 30%

It is important to explain the criteria used to determine the color scheme employed for illustration in the fiscal maps. First, a rate of return of 12.2% is selected as representing breakeven economics – projects with IRORs of at least 12.2% are considered economically viable. This return corresponds to a 10% real discount rate which is most commonly used by the oil and gas industry around the world. While, for large projects, it is not uncommon to see an 8% discount rate, 10% is used for this analysis.

The red section in the IROR table represents rates of return that are less than 12.2% indicating a No-Go/Stop investment decision. Projects that approach this rate but have IRORs that are still somewhat less than 12.2% are judged on a case-by-case basis. The green region represents projects that are clearly economically viable with IRORs between 12.2% and 17.3% (10% and 15% real). While 12.2% is the representative minimum rate, extending the range to 17.3% provides good upside flexibility for the investor. Projects with IRORs above 17.3% (the blue area) are considered very attractive, particularly when combined with NPVs such as those characteristic of oil sands developments. Cases with even more attractive IRORs above 30% (the yellow area) are identified to further delineate the upside possibilities. The red (Stop) section in the IROR table is carried to the other tables.

Nominal dollar government shares of less than 45% are considered very low or very attractive from an investor perspective. Shares less than 60% are considered low and shares greater than 70% are considered high. Very high government shares would exceed 85%. The following table of government shares is based on the international fiscal system analysis work of Dr. A. (Pedro) H. van Meurs.

For NPV_{10}/boe, values between 0 and 1.5 are considered Average. High values would be between 1.50 and 3.00. Values exceeding 3.00 are considered very high. The NPV values are assigned the same color codes as NPV_{10}/boe.

Color Code (Investor Perspective)		Gov. Share	Color Code (Investor Perspective)		NPV10 /boe
Red	Stop		Red	Stop	< 0.00
Orange	Very High	> 85%			
Brown	High	> 70%			
Green	Average	60% - 70%	Green	Average	0.00 - 1.50
Blue	Low	< 60%	Blue	High	1.50 - 3.00
Yellow	Very Low	< 45%	Yellow	Very High	> 3.00

Fiscal Maps
Cold Lake SAGD

Table 5.1a: Cold Lake SAGD (60,000 bpd) IROR ($Nominal)										
Prices Cases				Cost Sensitivities						
WTI	**WTI**	**Gas**	**Bitumen**	**$/Peakbbl**	**$25,650**	**$22,800**	**$19,000**	**$15,200**	**$13,300**	**$11,400**
US $	**Can $**	**Can $**	**Can $**	**Total $/bbl**	**17.61**	**16.41**	**14.81**	**13.21**	**12.41**	**11.61**
20	**22.55**	**$2.68**	**$12.40**		< 0	< 0	5.69%	9.55%	11.89%	14.66%
30	**33.82**	**$4.02**	**$18.60**		7.32%	9.38%	12.60%	16.68%	19.25%	22.39%
40	**45.10**	**$5.36**	**$24.80**		12.38%	14.50%	17.91%	22.39%	25.29%	28.84%
50	**56.37**	**$6.69**	**$31.00**		16.44%	18.70%	22.39%	27.34%	30.49%	34.51%
60	**67.64**	**$8.03**	**$37.20**		19.98%	22.39%	26.37%	31.75%	35.25%	39.39%
70	**78.92**	**$9.37**	**$43.40**		23.15%	25.78%	30.01%	35.77%	39.39%	43.97%
80	**90.19**	**$10.71**	**$49.61**		26.12%	28.84%	33.41%	39.39%	43.31%	48.09%
90	**101.47**	**$12.05**	**$55.81**		28.84%	31.75%	36.50%	42.89%	46.97%	51.81%
100	**112.74**	**$13.39**	**$62.01**		31.41%	34.51%	39.39%	46.10%	50.23%	55.34%
110	**124.01**	**$14.73**	**$68.21**		33.93%	37.04%	42.18%	49.03%	53.34%	58.63%
120	**135.29**	**$16.07**	**$74.41**		36.22%	39.39%	44.82%	51.81%	56.26%	61.74%

Table 5.1b: Cold Lake SAGD (60,000 bpd) Governments' Share ($Nominal)										
Prices Cases				Cost Sensitivities						
WTI	**WTI**	**Gas**	**Bitumen**	**$/Peakbbl**	**$25,650**	**$22,800**	**$19,000**	**$15,200**	**$13,300**	**$11,400**
US $	**Can $**	**Can $**	**Can $**	**Total $/bbl**	**17.61**	**16.41**	**14.81**	**13.21**	**12.41**	**11.61**
20	**22.55**	**2.68**	**12.40**		n/a	41%	35%	45%	46%	46%
30	**33.82**	**4.02**	**18.60**		44%	46%	47%	47%	47%	47%
40	**45.10**	**5.36**	**24.80**		47%	47%	47%	47%	47%	47%
50	**56.37**	**6.69**	**31.00**		47%	47%	47%	47%	47%	47%
60	**67.64**	**8.03**	**37.20**		47%	47%	47%	47%	47%	48%
70	**78.92**	**9.37**	**43.40**		47%	47%	47%	47%	48%	47%
80	**90.19**	**10.71**	**49.61**		47%	47%	47%	48%	48%	47%
90	**101.47**	**12.05**	**55.81**		47%	47%	47%	47%	47%	47%
100	**112.74**	**13.39**	**62.01**		47%	47%	48%	47%	48%	47%
110	**124.01**	**14.73**	**68.21**		47%	47%	47%	47%	48%	48%
120	**135.29**	**16.07**	**74.41**		47%	48%	47%	47%	48%	48%

Table 5.1c: Cold Lake SAGD (60,000 bpd)
Governments' Share ($Real 5%)

Prices Cases				Cost Sensitivities						
WTI	**WTI**	**Gas**	**Bitumen**	**$/Peakbbl**	**$25,650**	**$22,800**	**$19,000**	**$15,200**	**$13,300**	**$11,400**
US $	**Can $**	**Can $**	**Can $**	**Total $/bbl**	**17.61**	**16.41**	**14.81**	**13.21**	**12.41**	**11.61**
20	**22.55**	**2.68**	**12.40**		n/a	n/a	n/a	62%	55%	52%
30	**33.82**	**4.02**	**18.60**		92%	64%	55%	52%	50%	50%
40	**45.10**	**5.36**	**24.80**		55%	53%	51%	50%	49%	49%
50	**56.37**	**6.69**	**31.00**		52%	51%	50%	49%	49%	48%
60	**67.64**	**8.03**	**37.20**		50%	50%	49%	49%	48%	48%
70	**78.92**	**9.37**	**43.40**		50%	49%	49%	48%	48%	48%
80	**90.19**	**10.71**	**49.61**		49%	49%	48%	48%	48%	48%
90	**101.47**	**12.05**	**55.81**		49%	49%	48%	48%	48%	48%
100	**112.74**	**13.39**	**62.01**		49%	48%	48%	48%	48%	48%
110	**124.01**	**14.73**	**68.21**		48%	48%	48%	48%	48%	48%
120	**135.29**	**16.07**	**74.41**		48%	48%	48%	48%	48%	48%

Table 5.1d: Cold Lake SAGD (60,000 bpd)

NPV_{10}/boe ($Real 10%)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$25,650	$22,800	$19,000	$15,200	$13,300	$11,400
US $	Can $	Can $	Can $	Total $/bbl	17.61	16.41	14.81	13.21	12.41	11.61
20	22.55	$2.68	$12.40		-1.19	-0.90	-0.52	-0.18	-0.02	0.14
30	33.82	$4.02	$18.60		-0.53	-0.28	0.04	0.35	0.50	0.66
40	45.10	$5.36	$24.80		0.02	0.26	0.57	0.87	1.03	1.18
50	56.37	$6.69	$31.00		0.55	0.79	1.09	1.40	1.55	1.70
60	67.64	$8.03	$37.20		1.08	1.31	1.62	1.92	2.07	2.21
70	78.92	$9.37	$43.40		1.61	1.84	2.14	2.44	2.58	2.73
80	90.19	$10.71	$49.61		2.13	2.36	2.66	2.95	3.10	3.25
90	101.47	$12.05	$55.81		2.65	2.88	3.17	3.47	3.62	3.76
100	112.74	$13.39	$62.01		3.17	3.40	3.69	3.99	4.13	4.27
110	124.01	$14.73	$68.21		3.70	3.92	4.21	4.50	4.64	4.78
120	135.29	$16.07	$74.41		4.21	4.43	4.72	5.01	5.15	5.30

Table 5.1e: Cold Lake SAGD (60,000 bpd)

NPV_{10} (Millions $Real 10%)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$25,650	$22,800	$19,000	$15,200	$13,300	$11,400
US $	Can $	Can $	Can $	Total $/bbl	17.61	16.41	14.81	13.21	12.41	11.61
20	22.55	$2.68	$12.40		-678.94	-513.67	-296.21	-102.34	-10.87	78.96
30	33.82	$4.02	$18.60		-304.54	-162.17	20.63	198.26	285.88	373.44
40	45.10	$5.36	$24.80		12.49	146.38	323.20	497.91	584.74	670.91
50	56.37	$6.69	$31.00		315.52	447.55	622.39	796.76	880.26	967.74
60	67.64	$8.03	$37.20		616.19	746.87	919.85	1,092.25	1,177.98	1,260.05
70	78.92	$9.37	$43.40		914.12	1,046.98	1,216.21	1,387.22	1,470.06	1,555.29
80	90.19	$10.71	$49.61		1,213.83	1,341.81	1,513.06	1,680.07	1,764.05	1,848.82
90	101.47	$12.05	$55.81		1,509.54	1,638.37	1,806.89	1,976.68	2,059.39	2,140.95
100	112.74	$13.39	$62.01		1,804.29	1,935.49	2,100.09	2,270.15	2,351.25	2,433.64
110	124.01	$14.73	$68.21		2,104.58	2,229.45	2,395.00	2,562.01	2,643.89	2,724.67
120	135.29	$16.07	$74.41		2,398.39	2,520.11	2,689.90	2,854.60	2,934.87	3,017.13

Fiscal Maps
Athabasca SAGD

Table 5.2a: Athabasca SAGD (60,000 bpd)
IROR ($Nominal)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$25,650	$22,800	$19,000	$15,200	$13,300	$11,400
US $	Can $	Can $	Can $	Total $/bbl	17.61	16.41	14.81	13.21	12.41	11.61
20	22.55	$2.68	$10.39		< 0	< 0	< 0	5.63%	7.94%	10.69%
30	33.82	$4.02	$15.59		< 0	5.39%	8.51%	12.44%	14.86%	17.75%
40	45.10	$5.36	$20.79		8.29%	10.36%	13.61%	17.75%	20.37%	23.56%
50	56.37	$6.69	$25.99		12.23%	14.34%	17.75%	22.18%	25.08%	28.61%
60	67.64	$8.03	$31.18		15.52%	17.75%	21.38%	26.21%	29.29%	33.23%
70	78.92	$9.37	$36.38		18.44%	20.79%	24.65%	29.77%	33.23%	37.31%
80	90.19	$10.71	$41.58		21.10%	23.56%	27.67%	33.23%	36.71%	41.02%
90	101.47	$12.05	$46.78		23.56%	26.21%	30.46%	36.32%	39.98%	44.61%
100	112.74	$13.39	$51.97		26.09%	28.61%	33.23%	39.21%	43.02%	47.80%
110	124.01	$14.73	$57.17		28.08%	30.96%	35.68%	41.90%	46.00%	50.74%
120	135.29	$16.07	$62.37		30.19%	33.23%	38.06%	44.61%	48.65%	53.67%

Table 5.2b: Athabasca SAGD (60,000 bpd)
Governments' Share ($Nominal)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$25,650	$22,800	$19,000	$15,200	$13,300	$11,400
US $	Can $	Can $	Can $	Total $/bbl	17.61	16.41	14.81	13.21	12.41	11.61
20	22.55	2.68	10.39		n/a	n/a	59%	34%	43%	45%
30	33.82	4.02	15.59		39%	36%	45%	47%	47%	47%
40	45.10	5.36	20.79		45%	46%	47%	47%	47%	47%
50	56.37	6.69	25.99		47%	47%	47%	47%	47%	47%
60	67.64	8.03	31.18		47%	47%	47%	47%	47%	47%
70	78.92	9.37	36.38		47%	47%	47%	47%	47%	47%
80	90.19	10.71	41.58		47%	47%	47%	47%	47%	47%
90	101.47	12.05	46.78		47%	47%	47%	47%	47%	47%
100	112.74	13.39	51.97		47%	47%	47%	47%	48%	47%
110	124.01	14.73	57.17		47%	47%	47%	48%	47%	48%
120	135.29	16.07	62.37		47%	47%	47%	47%	48%	47%

Table 5.2c: Athabasca SAGD (60,000 bpd)
Governments' Share ($Real 5%)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$25,650	$22,800	$19,000	$15,200	$13,300	$11,400
US $	Can $	Can $	Can $	Total $/bbl	17.61	16.41	14.81	13.21	12.41	11.61
20	22.55	2.68	10.39		n/a	n/a	n/a	n/a	75%	57%
30	33.82	4.02	15.59		n/a	n/a	71%	55%	53%	51%
40	45.10	5.36	20.79		73%	60%	54%	51%	50%	49%
50	56.37	6.69	25.99		56%	53%	51%	50%	49%	49%
60	67.64	8.03	31.18		52%	51%	50%	49%	49%	48%
70	78.92	9.37	36.38		51%	50%	49%	49%	48%	48%
80	90.19	10.71	41.58		50%	49%	49%	48%	48%	48%
90	101.47	12.05	46.78		49%	49%	49%	48%	48%	48%
100	112.74	13.39	51.97		49%	49%	48%	48%	48%	48%
110	124.01	14.73	57.17		49%	49%	48%	48%	48%	48%
120	135.29	16.07	62.37		49%	48%	48%	48%	48%	48%

Table 5.2d: Athabasca SAGD (60,000 bpd)

NPV_{10}/boe ($Real 10%)

Prices Cases				Cost Sensitivities						
WTI	**WTI**	**Gas**	**Bitumen**	**$/Peakbbl**	**$25,650**	**$22,800**	**$19,000**	**$15,200**	**$13,300**	**$11,400**
US $	**Can $**	**Can $**	**Can $**	**Total $/bbl**	**17.61**	**16.41**	**14.81**	**13.21**	**12.41**	**11.61**
20	**22.55**	**$2.68**	**$10.39**		-1.45	-1.17	-0.79	-0.41	-0.24	-0.08
30	**33.82**	**$4.02**	**$15.59**		-0.93	-0.65	-0.31	0.02	0.17	0.33
40	**45.10**	**$5.36**	**$20.79**		-0.44	-0.19	0.13	0.44	0.59	0.75
50	**56.37**	**$6.69**	**$25.99**		0.00	0.24	0.55	0.85	1.01	1.16
60	**67.64**	**$8.03**	**$31.18**		0.43	0.66	0.97	1.27	1.42	1.58
70	**78.92**	**$9.37**	**$36.38**		0.85	1.08	1.38	1.68	1.84	1.99
80	**90.19**	**$10.71**	**$41.58**		1.26	1.49	1.80	2.10	2.25	2.39
90	**101.47**	**$12.05**	**$46.78**		1.68	1.91	2.21	2.51	2.66	2.81
100	**112.74**	**$13.39**	**$51.97**		2.13	2.32	2.63	2.92	3.06	3.21
110	**124.01**	**$14.73**	**$57.17**		2.51	2.73	3.03	3.32	3.48	3.62
120	**135.29**	**$16.07**	**$62.37**		2.92	3.15	3.44	3.74	3.88	4.03

Table 5.2e: Athabasca SAGD (60,000 bpd)

NPV_{10} (Millions $Real 10%)

Prices Cases				Cost Sensitivities						
WTI	**WTI**	**Gas**	**Bitumen**	**$/Peakbbl**	**$25,650**	**$22,800**	**$19,000**	**$15,200**	**$13,300**	**$11,400**
US $	**Can $**	**Can $**	**Can $**	**Total $/bbl**	**17.61**	**16.41**	**14.81**	**13.21**	**12.41**	**11.61**
20	**22.55**	**$2.68**	**$10.39**		-826.20	-666.83	-450.41	-234.31	-136.42	-43.64
30	**33.82**	**$4.02**	**$15.59**		-531.46	-370.16	-174.28	9.73	99.39	187.97
40	**45.10**	**$5.36**	**$20.79**		-247.97	-108.08	73.52	250.63	337.98	424.39
50	**56.37**	**$6.69**	**$25.99**		1.92	135.58	313.29	486.75	573.80	660.13
60	**67.64**	**$8.03**	**$31.18**		242.89	375.94	551.52	724.98	809.41	897.05
70	**78.92**	**$9.37**	**$36.38**		481.57	613.25	786.60	957.93	1,046.56	1,130.69
80	**90.19**	**$10.71**	**$41.58**		718.99	848.78	1,023.04	1,196.07	1,278.70	1,362.46
90	**101.47**	**$12.05**	**$46.78**		954.88	1,087.47	1,256.03	1,429.66	1,512.22	1,597.26
100	**112.74**	**$13.39**	**$51.97**		1,212.48	1,320.26	1,495.09	1,662.63	1,743.35	1,828.44
110	**124.01**	**$14.73**	**$57.17**		1,427.08	1,556.66	1,726.32	1,893.20	1,978.91	2,058.86
120	**135.29**	**$16.07**	**$62.37**		1,662.93	1,794.10	1,961.36	2,129.68	2,209.84	2,293.02

Fiscal Maps
Athabasca Mine

Table 5.3a: Athabasca Mine (200,000 bpd)
IROR ($Nominal)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$35,750	$32,890	$28,600	$25,740	$21,450	$18,590
US $	Can $	Can $	Can $	Total $/bbl	15.33	14.24	12.60	11.51	9.87	8.78
20	22.55	$2.68	$10.39		< 0	< 0	< 0	< 0	5.17%	7.40%
30	33.82	$4.02	$15.59		< 0	4.62%	6.84%	8.44%	11.27%	13.57%
40	45.10	$5.36	$20.79		7.82%	9.10%	11.27%	12.95%	16.00%	18.56%
50	56.37	$6.69	$25.99		11.27%	12.60%	14.90%	16.71%	20.09%	22.98%
60	67.64	$8.03	$31.18		14.22%	15.63%	18.09%	20.09%	23.82%	27.04%
70	78.92	$9.37	$36.38		16.86%	18.36%	21.04%	23.19%	27.26%	30.68%
80	90.19	$10.71	$41.58		19.30%	20.94%	23.82%	26.16%	30.49%	34.16%
90	101.47	$12.05	$46.78		21.59%	23.34%	26.47%	28.90%	33.49%	37.32%
100	112.74	$13.39	$51.97		23.82%	25.67%	28.90%	31.52%	36.28%	40.30%
110	124.01	$14.73	$57.17		25.97%	27.82%	31.24%	33.96%	38.98%	43.09%
120	135.29	$16.07	$62.37		27.91%	29.90%	33.49%	36.28%	41.48%	45.61%

Table 5.3b: Athabasca Mine (200,000 bpd)
Governments' Share ($Nominal)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$35,750	$32,890	$28,600	$25,740	$21,450	$18,590
US $	Can $	Can $	Can $	Total $/bbl	15.33	14.24	12.60	11.51	9.87	8.78
20	22.55	$2.68	$10.39		n/a	n/a	n/a	43%	33%	42%
30	33.82	$4.02	$15.59		38%	35%	42%	45%	47%	47%
40	45.10	$5.36	$20.79		44%	46%	47%	47%	47%	47%
50	56.37	$6.69	$25.99		47%	47%	47%	47%	47%	47%
60	67.64	$8.03	$31.18		47%	47%	47%	47%	47%	47%
70	78.92	$9.37	$36.38		47%	47%	47%	47%	47%	48%
80	90.19	$10.71	$41.58		47%	47%	47%	47%	47%	47%
90	101.47	$12.05	$46.78		47%	47%	47%	47%	47%	48%
100	112.74	$13.39	$51.97		47%	47%	47%	47%	48%	48%
110	124.01	$14.73	$57.17		47%	47%	47%	48%	47%	48%
120	135.29	$16.07	$62.37		47%	48%	47%	48%	48%	48%

Table 5.3c: Athabasca Mine (200,000 bpd)
Governments' Share ($Real 5%)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$35,750	$32,890	$28,600	$25,740	$21,450	$18,590
US $	Can $	Can $	Can $	Total $/bbl	15.33	14.24	12.60	11.51	9.87	8.78
20	22.55	$2.68	$10.39		n/a	n/a	n/a	n/a	n/a	86%
30	33.82	$4.02	$15.59		n/a	n/a	118%	69%	56%	53%
40	45.10	$5.36	$20.79		78%	64%	56%	53%	51%	50%
50	56.37	$6.69	$25.99		56%	54%	52%	51%	50%	49%
60	67.64	$8.03	$31.18		52%	51%	50%	50%	49%	48%
70	78.92	$9.37	$36.38		51%	50%	49%	49%	48%	48%
80	90.19	$10.71	$41.58		50%	49%	49%	49%	48%	48%
90	101.47	$12.05	$46.78		49%	49%	49%	48%	48%	48%
100	112.74	$13.39	$51.97		49%	49%	48%	48%	48%	48%
110	124.01	$14.73	$57.17		49%	48%	48%	48%	48%	48%
120	135.29	$16.07	$62.37		48%	48%	48%	48%	48%	48%

Table 5.3d: Athabasca Mine (200,000 bpd)										
NPV_{10}/boe ($Real 10%)										
Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$35,750	$32,890	$28,600	$25,740	$21,450	$18,590
US $	Can $	Can $	Can $	Total $/bbl	15.33	14.24	12.60	11.51	9.87	8.78
20	22.55	$2.68	$10.39		0.00	-1.45	-1.11	-0.89	-0.55	-0.34
30	33.82	$4.02	$15.59		-1.14	-0.91	-0.58	-0.38	-0.08	0.11
40	45.10	$5.36	$20.79		-0.61	-0.40	-0.11	0.08	0.37	0.55
50	56.37	$6.69	$25.99		-0.14	0.06	0.34	0.53	0.81	1.00
60	67.64	$8.03	$31.18		0.31	0.50	0.78	0.97	1.25	1.44
70	78.92	$9.37	$36.38		0.76	0.95	1.23	1.41	1.69	1.87
80	90.19	$10.71	$41.58		1.20	1.39	1.67	1.85	2.13	2.30
90	101.47	$12.05	$46.78		1.64	1.83	2.11	2.29	2.56	2.74
100	112.74	$13.39	$51.97		2.08	2.27	2.54	2.73	2.99	3.16
110	124.01	$14.73	$57.17		2.53	2.70	2.98	3.16	3.43	3.60
120	135.29	$16.07	$62.37		2.96	3.14	3.41	3.59	3.85	4.02

Table 5.3e: Athabasca Mine (200,000 bpd)										
NPV_{10} (Millions $Real 10%)										
Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$35,750	$32,890	$28,600	$25,740	$21,450	$18,590
US $	Can $	Can $	Can $	Total $/bbl	15.33	14.24	12.60	11.51	9.87	8.78
20	22.55	$2.68	$10.39		-55.06	-3,279.55	-2,512.38	-2,003.50	-1,238.11	-757.82
30	33.82	$4.02	$15.59		-2,569.81	-2,055.49	-1,319.12	-855.24	-185.29	247.43
40	45.10	$5.36	$20.79		-1,370.11	-912.45	-247.06	185.76	825.46	1,248.85
50	56.37	$6.69	$25.99		-308.82	125.14	768.80	1,189.99	1,826.46	2,245.55
60	67.64	$8.03	$31.18		709.18	1,137.25	1,766.43	2,191.76	2,820.32	3,240.69
70	78.92	$9.37	$36.38		1,713.84	2,133.35	2,765.40	3,181.25	3,807.77	4,212.88
80	90.19	$10.71	$41.58		2,708.43	3,137.92	3,760.42	4,178.75	4,795.57	5,199.29
90	101.47	$12.05	$46.78		3,699.44	4,124.35	4,759.52	5,164.51	5,774.57	6,169.65
100	112.74	$13.39	$51.97		4,700.53	5,122.07	5,738.35	6,146.94	6,743.44	7,138.73
110	124.01	$14.73	$57.17		5,705.76	6,098.08	6,715.19	7,120.11	7,726.01	8,111.58
120	135.29	$16.07	$62.37		6,673.65	7,077.03	7,699.43	8,092.13	8,692.95	9,071.35

Fiscal Maps
Athabasca Mine & Upgrader Integrated

Table 5.4a: Athabasca Integrated Mine & Upgrader (170,000 bpd)
IROR ($Nominal)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$92,647	$85,235	$74,118	$66,706	$55,588	$48,176
US $	Can $	Can $	Can $	Total $/bbl	33.61	31.38	28.04	25.82	22.48	20.26
20	22.55	$2.68	$10.39		< 0	< 0	< 0	< 0	< 0	< 0
30	33.82	$4.02	$15.59		< 0	3.74%	5.75%	7.22%	9.78%	11.86%
40	45.10	$5.36	$20.79		6.65%	7.81%	9.78%	11.31%	14.05%	16.36%
50	56.37	$6.69	$25.99		9.86%	11.08%	13.19%	14.84%	17.88%	20.44%
60	67.64	$8.03	$31.18		12.45%	13.72%	15.93%	17.72%	21.03%	23.90%
70	78.92	$9.37	$36.38		14.83%	16.17%	18.57%	20.49%	24.11%	27.21%
80	90.19	$10.71	$41.58		17.02%	18.47%	21.03%	23.11%	27.01%	30.37%
90	101.47	$12.05	$46.78		19.07%	20.61%	23.37%	25.59%	29.75%	33.33%
100	112.74	$13.39	$51.97		21.03%	22.67%	25.59%	27.94%	32.36%	36.11%
110	124.01	$14.73	$57.17		22.92%	24.62%	27.70%	30.19%	34.86%	38.75%
120	135.29	$16.07	$62.37		24.70%	26.50%	29.75%	32.36%	37.21%	41.23%

Table 5.4b: Athabasca Integrated Mine & Upgrader (170,000 bpd)
Governments' Share ($Nominal)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$92,647	$85,235	$74,118	$66,706	$55,588	$48,176
US $	Can $	Can $	Can $	Total $/bbl	33.61	31.38	28.04	25.82	22.48	20.26
20	22.55	2.68	10.39		n/a	n/a	n/a	n/a	44%	34%
30	33.82	4.02	15.59		36%	34%	38%	39%	40%	40%
40	45.10	5.36	20.79		39%	40%	40%	40%	40%	40%
50	56.37	6.69	25.99		40%	41%	41%	41%	41%	41%
60	67.64	8.03	31.18		40%	40%	40%	40%	40%	40%
70	78.92	9.37	36.38		40%	40%	40%	40%	40%	40%
80	90.19	10.71	41.58		40%	40%	40%	40%	40%	40%
90	101.47	12.05	46.78		40%	40%	40%	40%	40%	40%
100	112.74	13.39	51.97		40%	40%	40%	40%	40%	40%
110	124.01	14.73	57.17		40%	40%	40%	40%	40%	40%
120	135.29	16.07	62.37		40%	40%	40%	40%	40%	40%

Table 5.4c: Athabasca Integrated Mine & Upgrader (170,000 bpd)
Governments' Share ($Real 5%)

Prices Cases				Cost Sensitivities						
WTI	WTI	Gas	Bitumen	$/Peakbbl	$92,647	$85,235	$74,118	$66,706	$55,588	$48,176
US $	Can $	Can $	Can $	Total $/bbl	33.61	31.38	28.04	25.82	22.48	20.26
20	22.55	2.68	10.39		n/a	n/a	n/a	n/a	n/a	n/a
30	33.82	4.02	15.59		n/a	n/a	n/a	94%	55%	49%
40	45.10	5.36	20.79		148%	74%	55%	50%	46%	44%
50	56.37	6.69	25.99		55%	51%	47%	45%	44%	43%
60	67.64	8.03	31.18		48%	46%	45%	44%	43%	42%
70	78.92	9.37	36.38		45%	44%	43%	43%	42%	42%
80	90.19	10.71	41.58		44%	43%	43%	42%	42%	41%
90	101.47	12.05	46.78		43%	43%	42%	42%	41%	41%
100	112.74	13.39	51.97		43%	42%	42%	42%	41%	41%
110	124.01	14.73	57.17		42%	42%	42%	41%	41%	41%
120	135.29	16.07	62.37		42%	42%	41%	41%	41%	41%

Table 5.4d: Athabasca Integrated Mine & Upgrader (170,000 bpd)

NPV$_{10}$/boe ($Real 10%)

Prices Cases				Cost Sensitivities						
WTI	**WTI**	**Gas**	**Bitumen**	**$/Peakbbl**	**$92,647**	**$85,235**	**$74,118**	**$66,706**	**$55,588**	**$48,176**
US $	**Can $**	**Can $**	**Can $**	**Total $/bbl**	**33.61**	**31.38**	**28.04**	**25.82**	**22.48**	**20.26**
20	**22.55**	**$2.68**	**$10.39**		-0.03	-3.56	-2.79	-2.70	-1.94	-1.43
30	**33.82**	**$4.02**	**$15.59**		-3.01	-2.50	-1.74	-1.26	-0.54	-0.07
40	**45.10**	**$5.36**	**$20.79**		-1.92	-1.43	-0.72	-0.25	0.45	0.92
50	**56.37**	**$6.69**	**$25.99**		-0.85	-0.38	0.31	0.77	1.45	1.91
60	**67.64**	**$8.03**	**$31.18**		0.10	0.57	1.26	1.73	2.42	2.88
70	**78.92**	**$9.37**	**$36.38**		1.09	1.55	2.25	2.71	3.40	3.86
80	**90.19**	**$10.71**	**$41.58**		2.07	2.54	3.23	3.69	4.38	4.84
90	**101.47**	**$12.05**	**$46.78**		3.05	3.51	4.21	4.67	5.36	5.81
100	**112.74**	**$13.39**	**$51.97**		4.03	4.50	5.19	5.65	6.33	6.78
110	**124.01**	**$14.73**	**$57.17**		5.02	5.47	6.16	6.62	7.30	7.75
120	**135.29**	**$16.07**	**$62.37**		5.99	6.45	7.14	7.59	8.27	8.71

Table 5.4e: Athabasca Integrated Mine & Upgrader (170,000 bpd)

NPV$_{10}$ (Millions $Real 10%)

Prices Cases				Cost Sensitivities						
WTI	**WTI**	**Gas**	**Bitumen**	**$/Peakbbl**	**$92,647**	**$85,235**	**$74,118**	**$66,706**	**$55,588**	**$48,176**
US $	**Can $**	**Can $**	**Can $**	**Total $/bbl**	**33.61**	**31.38**	**28.04**	**25.82**	**22.48**	**20.26**
20	**22.55**	**$2.68**	**$10.39**		-55.06	-6,823.98	-5,358.76	-5,180.66	-3,713.76	-2,738.14
30	**33.82**	**$4.02**	**$15.59**		-5,768.49	-4,784.75	-3,343.82	-2,409.86	-1,034.31	-130.70
40	**45.10**	**$5.36**	**$20.79**		-3,677.99	-2,750.37	-1,379.10	-475.50	865.64	1,760.16
50	**56.37**	**$6.69**	**$25.99**		-1,627.97	-736.32	592.04	1,468.56	2,785.75	3,655.41
60	**67.64**	**$8.03**	**$31.18**		188.55	1,085.87	2,416.07	3,312.31	4,640.52	5,530.48
70	**78.92**	**$9.37**	**$36.38**		2,082.28	2,969.19	4,305.91	5,188.20	6,518.96	7,394.00
80	**90.19**	**$10.71**	**$41.58**		3,966.90	4,865.20	6,187.36	7,072.83	8,397.61	9,273.08
90	**101.47**	**$12.05**	**$46.78**		5,846.68	6,738.02	8,074.81	8,952.80	10,268.72	11,137.65
100	**112.74**	**$13.39**	**$51.97**		7,734.19	8,622.16	9,947.57	10,825.49	12,131.83	12,994.22
110	**124.01**	**$14.73**	**$57.17**		9,626.18	10,493.58	11,814.67	12,691.95	14,004.56	14,854.40
120	**135.29**	**$16.07**	**$62.37**		11,490.05	12,362.76	13,691.64	14,558.19	15,858.81	16,701.49