PRELIMINARY FISCAL EVALUATION OF ALBERTA OIL SANDS TERMS

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<u>Important note:</u>

This report is being provided to the Department of Energy under a consulting contract with Pedro Van Meurs .

The report provides a preliminary evaluation of the Alberta oil sands terms and the initial results of an economic-fiscal analysis. The report represents the findings, analysis and interpretation of the author and does not necessarily reflect the views of the Minister of Energy or Department of Energy.

It is intended to provide additional information for consideration by the Royalty Review Panel.

The Department of Energy welcomes comments on this report by third parties.

EXECUTIVE SUMMARY

The report is an economic evaluation of the current fiscal terms applicable to Alberta oil sands.

There is a wide variety of different oil sands projects in Alberta:

- **Projects can be based on mining the bitumen or the production of bitumen through wells and in this case steam is injected to make the bitumen flow to the wells.**
- **Some projects have upgraders that convert the bitumen to high quality synthetic crude oil. Other projects do not have upgraders and export bitumen mixed with condensates directly into crude pipelines.**
- **Projects differ in size. For example, some projects may target a cumulative bitumen production of 600 million barrels, other projects target 2200 million barrels.**
- **Projects also differ with respect to the price that can be obtained for the bitumen. The price depends on the quality of the bitumen and the associated transport costs.**

In order to reflect these differences in the economic analysis the report defines five different cases for study.

The differences in bitumen values could be rather considerable. It was assumed that for Cold Lake the bitumen value would be equal to 60% of the West Texas Intermediate ("WTI") prices. For Athabasca it was assumed that the value would be 45% of the WTI prices.

It is important to note that at this time there is no objective, independent and publicly published standard for oil sands bitumen prices. There is considerable volatility in these prices relative to crude oils. Therefore, it is difficult to know what the fair market value is for calculating royalties.

The cost of oil sands projects varies enormously. In order to reflect the entire cost range, seven different levels of costs were used. The capital expenditures of high cost projects could be twice those of low cost projects on a per barrel basis. The same is true for operating costs. An important component is the energy costs for the operations. Gas requirements are high for projects that produce bitumen through wells with steam injection. About one thousand cubic feet of natural gas could be required per barrel of bitumen produced.

Costs have escalated considerably over the last few years, but oil prices are now also considerably higher.

An analysis was done to evaluate the profitability of oil sand projects to investors under current conditions based on the generic royalty regime based on bitumen values.

In general, new oil sand projects that are low cost and receive high values for bitumen are attractive to investors for a price of US $ 30 per barrel WTI. Projects that are high cost and and receive low bitumen values become attractive at US $ 50 per barrel WTI. Over US $ 60 per barrel WTI most oil sand projects are very attractive.

Most conventional oil projects in the world are attractive at much lower prices. Therefore, on a relative basis oil sands projects represent a price risk for investors. Under low prices oil sands projects could cause losses while many international conventional oil projects would remain profitable.

Oil sands projects are very large in terms of cumulative production per project by international standards. There are few new conventional oil projects in the world that are in the size range of 600 million barrels to two billion barrels. Therefore at US $ 60 per barrel WTI or higher, oil sands projects generate unusually high total profits for investors per project. This makes these projects very valuable. There are few projects in the world creating such attractive total values to investors at these price levels.

Upgrading is a very important method to create additional value for the investor. About half the value of integrated projects is attributable to upgrading. This value created through upgrading is therefore integral to the resource value to Alberta. In the case of production of bitumen only, the value created through subsequent upgrading by others represents a significant "associated value" of the production.

In Alberta the oil sands royalties mostly based on net production. Internationally, most royalties are based on a percentage of the gross value of the production. In order to compare the Alberta royalties with international royalties, the Alberta royalties were converted for each price and cost level to equivalent royalties on gross revenues. Subsequently, royalties were evaluated on the basis of the gross revenues from bitumen and from synthetic crude oil.

From a "bitumen value" perspective, the oil sands royalties over the duration of the project are comparable to international royalty levels. The royalties are average, in the 10% to 15% range. It should be noted that this observation relates to the total amount of royalties received over the life of the project. By international standards a royalty of 1% until payout is very low.

From a "synthetic crude oil value" perspective, the Athabasca oil sands royalties are low compared to international standards, in the 4.5% to 7.5% range. Under low prices this may be acceptable. However, under high prices this is clearly unattractive to Alberta.

One of the objectives of the royalty review is to determine whether Albertans receive a fair share from their oil and gas resources.

Alberta has royalties and corporate income tax as the main sources of income. Many oil exporting jurisdictions have in addition to (or instead of) royalties and corporate income tax, other income sources as well. These include production shares for government, special resource taxes or direct government participation in the ventures. Therefore, the "fair share" is based on the total of many different types of payments to government.

Several jurisdictions use a bonus bid system such as Alberta. However, bonus bids are voluntary payments and are therefore not part of the regular government income.

Canada, the United States, Australia and a few other countries have federal as well as provincial oil and gas payments to government. However, most countries have just national system. Therefore, in order to compare Alberta with the world, the share of Alberta and the Federal Government have to be considered together.

An analysis was done in order to analyze the Alberta plus Federal share consisting of royalties plus corporate income tax. The share calculated on the basis of the total project profits before taking out the share.

For projects that produce bitumen, the total share for both governments is about 47.5% of the profits on the bitumen production. This is low be international standards. Typically the share for government on average is about 55- 65%. For major producing and exporting countries, this share is much higher.

For projects that produce synthetic crude oil, the total share for both governments is 38% – 39.5% of the profits of the integrated synthetic crude production. This is very low by international standards.

In either case the share is "flat". This means it is the same irrespective of the level of prices or costs. This is largely due to the fact that both royalties and corporate income tax are based on net income.

The low or very low government share may be reasonable under conditions of low prices and high costs. However, it seems that there is considerable justification for establishing a higher share under conditions of high prices and low costs.

Some of the companies, such as Suncor and Syncrude, are currently operating on the basis of agreements based on net profits of the integrated synthetic crude production. These companies have the option to move to bitumen values instead. These values are much lower. Therefore, if companies exercise this option, it will result in a very significant revenue reduction for Alberta.

MAIN REPORT

1. INTRODUCTION

This report is provided at the request of the Department of Energy of the province of Alberta. The work is being provided under a consulting contract with Alberta.

The report contains a preliminary evaluation of the Alberta oil sands terms. The purpose is to "survey the terrain" and to identify areas and raise issues that need further evaluation and possible feed back from Albertans and the Royalty Review Panel. The report provides the initial results of an economic-fiscal analysis. However, it is too early in this Royalty Review to reach specific conclusions at this time.

The economic analysis is based on information provided by the Department of Energy. The cost and revenue data are similar to the ones published in Technical Royalty Report # 1 of the Department of Energy entitled *"Alberta's Oil Sands Fiscal System - Historical Context and System Performance"*.

However, the cash flows used in this analysis are not identical to the ones in report # 1. The reason is that the model used for analysis, the "World Fiscal Model" of Van Meurs Corporation, requires inputs in a somewhat different format. This model is being used in order to be able to make in subsequent reports comparisons with other fiscal regimes on a world wide basis. Also, I used my own judgment in interpreting the many data sources available in the Department.

In view of the wide range of possible cost and price scenarios, I will use the "fiscal map" methodology. This approach was also followed by the Department to produce cost-price "maps" of the various results.

2. ECONOMIC ASSUMPTIONS

2.1. Economic Cases

Five different economic cases were evaluated. Cases involving Steam Assisted Gravity Drainage ("SAGD") operations were assessed for both the Athabasca and Cold Lake. Athabasca mining and integrated operations with upgrading were also assessed.

The five cases are all based on the currently applicable generic fiscal regime:

- "Cold Lake SAGD" – Cold Lake bitumen based production based on the SAGD process. This case is for bitumen of about 11 degrees API.
- "Athabasca SAGD" - Athabasca bitumen production based on the SAGD process
- "Athabasca SAGD + Upgrading" - Athabasca SAGD bitumen production based on SAGD combined with upgrading
- "Athabasca Mine" - Athabasca bitumen production based on mining
- "Athabasca Mine + Upgrading" - Athabasca bitumen production based on mining combined with upgrading

The Athabasca Mine + Upgrading was also analyzed on the basis of the currently applicable fiscal terms to Suncor and Syncrude, whereby the base royalty and profit share are being assessed on the value of the synthetic crude oil rather than the value of the bitumen.

It should be noted that at this time there are few SAGD+Upgrading projects. Nevertheless SAGD is becoming an increasingly important production method and therefore it is important to understand the economics of SAGD plus Upgrading.

In the Cold Lake area Cyclic Steam Simulation ("CSS") may be a preferred method of production over SAGD. In this analysis no separate scenario was developed for Cold Lake using CSS.

The current generic fiscal regime also applies to conventional heavy oil production in Northern Alberta. However, this matter was not evaluated at this time.

2.2. Production, Cost and Price Data

At this stage of the economic-fiscal evaluation relatively simple cash flows are being used. The purpose is to scope the general economic and fiscal behavior of the Alberta fiscal terms. For this purpose such generalized cash flows are adequate. The following production scenarios were used:

Cases	Peak Bitumen Production	Peak Synthetic Crude Oil Production	Cumulative Bitumen Production	Cumulative Synthetic Crude Oil Production
	(barrels per day)	(barrels per day)	(million barrels)	(million barrels)
Cold Lake SAGD	60,000	--	600	--
Athabasca:				
SAGD	60,000	--	600	--
SAGD+Upgrader	60,000	51,000	600	510
Mine	200,000	--	2200	--
Mine+Upgrader	200,000	170,000	2200	1870

As can be seen, it was assumed that the upgrading would result in a level of synthetic crude oil ("SCO") production that would be 85% of the bitumen production. This is due to the losses inherent in the upgrading process. This percentage varies, of course, with the degree and method of upgrading and the quality of the original bitumen.

The "peak" production is the level of production achieved after full development of the project. In the cash flows it was assumed that the production would be developed in two separate phases, each producing half the final "peak".

From the data available in the Department of Energy it is clear that costs vary over a wide range. Therefore seven cost levels were selected. "Cost-1" represents the lowest level and "Cost-7" the highest level. Projects with costs over this entire range do exist. "Typical" or "average" costs may be represented by Cost-3 or Cost-4.

At this time the costs in Alberta are subject to strong local escalation. If in the future costs continue to escalate strongly Cost-5 may become more typical. If on the other hand cost escalation is reversed as a result of a moderation in oil prices and/or new fiscal terms, Cost-2 may be more representative of long term operations. This may also be the cost level that could represent significant further technological improvement or superior management of costs and budgets on the part of some companies.

All costs are expressed in Canadian 2007 real dollars.

Following Tables 2.1 through 2.5 provide the cost and price ranges that were used for the five different economic cases. No differences were assumed between Cold Lake and Athabasca SAGD in terms of costs.

Table 2.1. COLD LAKE DATA
(Can 2007 $)

		COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
Field Size	(million Bit barrels)	600	600	600	600	600	600	600
Peak Bitumen production	(thousand barrels per day)	60	60	60	60	60	60	60
Start cash flow	(year)	2007	2007	2007	2007	2007	2007	2007
First production	(year)	2011	2011	2011	2011	2011	2011	2011
Final peak production	(year)	2016	2016	2016	2016	2016	2016	2016
Capex/peak barrel	($/Bit bbl)	$26,167	$23,551	$20,934	$18,317	$15,700	$13,084	$10,467
Out-of-Pocket/peak barrel	($/Bit bbl)	$10,319	$9,287	$8,255	$7,223	$6,191	$5,160	$4,128
Total capex/bbl	($/Bit bbl)	$5.00	$4.50	$4.00	$3.50	$3.00	$2.50	$2.00
Development Phases		2	2	2	2	2	2	2
Total non-energy opex/bbls	($/Bit bbl)	$6.15	$5.59	$5.03	$4.48	$3.07	$3.36	$2.80
Energy requirement per bbl	(Mcf/Bit bbl)	1	1	1	1	1	1	1
Gas price	($/Mcf)	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8
Bitumen Price	($/Bit bbl)	60% CanWTI	60% CanWTI	60% CanWTI	60% CanWTI	60% CanWTI	60% CanWTI	60% CanWTI

Table 2.2. SAGD ATHABASCA
(Can 2007 $)

		COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
Field Size	(million Bit barrels)	600	600	600	600	600	600	600
Peak Bitumen production	(thousand barrels per day)	60	60	60	60	60	60	60
Start cash flow	(year)	2007	2007	2007	2007	2007	2007	2007
First production	(year)	2011	2011	2011	2011	2011	2011	2011
Final peak production	(year)	2016	2016	2016	2016	2016	2016	2016
Capex/peak barrel	($/peak Bit bbl per day)	$26,167	$23,551	$20,934	$18,317	$15,700	$13,084	$10,467
Out-of-Pocket/peak barrel	($/Bit bbl)	$10,319	$9,287	$8,255	$7,223	$6,191	$5,160	$4,128
Total capex/bbl	($/Bit bbl)	$5.00	$4.50	$4.00	$3.50	$3.00	$2.50	$2.00
Development Phases		2	2	2	2	2	2	2
Total non-energy opex/bbl	($/Bit bbl)	$6.15	$5.59	$5.03	$4.48	$3.92	$3.36	$2.80
Energy requirement per bbl	(Mcf/Bit bbl)	1	1	1	1	1	1	1
Gas price	($/Mcf)	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8
Bitumen Price	($/Bit bbl)	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI

Table 2.3. SAGD ATHABASCA WITH UPGRADING
(Can 2007 $)

		COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
Field Size	(millionSCO barrels)	510	510	510	510	510	510	510
Peak Bitumen production	(thousand barrels per day)	60	60	60	60	60	60	60
Peak SCO production	(thousand barrels per day)	51	51	51	51	51	51	51
SCO/Bitumen ratio		85%	85%	85%	85%	85%	85%	85%
Start cash flow	(year)	2007	2007	2007	2007	2007	2007	2007
First production	(year)	2011	2011	2011	2011	2011	2011	2011
Final peak production	(year)	2016	2016	2016	2016	2016	2016	2016
Capex/peak SCO barrel	($/peak SCO bbl per day)	$80,458	$73,240	$66,022	$58,804	$51,586	$44,369	$37,151
Out-of-Pocket/peak barrel	($/Bit bbl)	$35,669	$32,495	$29,320	$26,145	$22,970	$19,796	$16,621
Production capex/bbl	($/SCO bbl)	$5.88	$5.29	$4.71	$4.12	$3.53	$2.94	$2.35
Upgrading capex/bbl	($/SCO bbl)	$5.49	$5.03	$4.57	$4.12	$3.66	$3.20	$3.75
Development Phases		2	2	2	2	2	2	2
Prod non-energy opex/bbl	($/SCO bbl)	$7.24	$6.58	$5.92	$5.27	$4.61	$3.95	$3.29
Upgr non-energy opex/bbl	($/SCO bbl)	$5.36	$4.88	$4.39	$3.90	$3.41	$2.92	$2.44
Prod energy per bbl	(Mcf/SCO bbl)	1.18	1.18	1.18	1.18	1.18	1.18	1.18
Upgr energy per bbl	(Mcf/SCO bbl)	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Gas price	($/Mcf)	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8
Synthetic Crude Oil price	($/SCO bbl)	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI

Table 2.4. MINE ATHABASCA
(Can 2007 $)

		COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
Field Size	(million Bit barrels)	2200	2200	2200	2200	2200	2200	2200
Peak Bitumen production	(thousand barrels per day)	200	200	200	200	200	200	200
Start cash flow	(year)	2007	2007	2007	2007	2007	2007	2007
First production	(year)	2012	2012	2012	2012	2012	2012	2012
Final peak production	(year)	2016	2016	2016	2016	2016	2016	2016
Capex/peak barrel	($/peak Bit bbl per day)	$31,421	$28,279	$25,137	$21,995	$18,853	$15,710	$12,569
Out-of-Pocket/peak barrel	($/Bit bbl)	$15,714	$14,143	$12,571	$11,000	$9,429	$7,857	$6,286
Total capex/bbl	($/Bit bbl)	$4.18	$3.76	$3.34	$2.93	$2.51	$2.09	$1.67
Development Phases		2	2	2	2	2	2	2
Total non-energy opex/bbl	($/Bit bbl)	$9.49	$8.63	$7.76	$6.90	$6.04	$5.18	$4.31
Energy requirement per bbl	(Mcf/Bit bbl)	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Gas price	($/Mcf)	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8
Bitumen Price	($/Bit bbl)	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI	45% CanWTI

Table 2.5. MINE ATHABASCA WITH UPGRADING
(Can 2007 $)

		COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
Field Size	(million SCO barrels)	1870	1870	1870	1870	1870	1870	1870
Peak Bitumen production	(thousand barrels per day)	200	200	200	200	200	200	200
Peak SCO production	(thousand barrels per day)	170	170	170	170	170	170	170
SCO/Bitumen ratio		85%	85%	85%	85%	85%	85%	85%
Start cash flow	(year)	2007	2007	2007	2007	2007	2007	2007
First production	(year)	2012	2012	2012	2012	2012	2012	2012
Final peak production	(year)	2016	2016	2016	2016	2016	2016	2016
Capex/peak SCO barrel	($/peak SCO bbl per day)	$84,361	$75,925	$67,489	$59,053	$50,617	$42,181	$33,745
Out-of-Pocket/peak barrel	($/Bit bbl)	$41,176	$37,059	$32,941	$28,824	$24,706	$20,588	$16,471
Production capex/bbl	($/SCO bbl)	$4.92	$4.43	$3.93	$3.44	$2.95	$2.46	$1.97
Upgrading capex/bbl	($/SCO bbl)	$4.77	$4.29	$3.81	$3.34	$2.86	$2.38	$1.91
Development Phases		2	2	2	2	2	2	2
Prod non-energy opex/bbl	($/SCO bbl)	$11.16	$10.15	$9.13	$8.12	$7.10	$6.09	$5.07
Upgr non-energy opex/bbl	($/SCO bbl)	$4.81	$4.38	$3.94	$3.50	$3.06	$2.63	$2.19
Prod energy per bbl	(Mcf/SCO bbl)	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Upgr energy per bbl	(Mcf/SCO bbl)	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Gas price	($/Mcf)	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8	CanWTI/8
Synthetic Crude Oil price	($/SCO bbl)	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI	100% CanWTI

The capital expenditures ("Capex") per peak flowing barrel include the capital expenditures in the year that the peak production was being reached. All capital costs (facilities, drilling, capital maintenance) are included in this indicator.

The "out-of-pocket" capex per peak barrel are the capital expenditures made prior to the first start of production.

The capital expenditures are divided in "production capex" and "upgrading capex". In determining these values common costs for utilities, off sites, site preparation, etc., where reasonably allocated to "production" and "upgrading", based on methodologies used in the Department of Energy.

Operating costs were divided in "non-energy" and "energy" per barrel. The "energy" costs are the costs of natural gas required for the operations. For convenience, electricity costs were included in "non-energy", despite the fact that electricity is also energy, of course.

The "energy" costs were determined based on the natural gas used in terms of thousand cubic feet ("Mcf") per barrel to produce or upgrade a barrel. For SAGD a level of one Mcf per barrel was used to produce a barrel of bitumen. The gas requirements vary considerably with the actual SAGD process.

The gas price was assumed to be the WTI price expressed in Canadian dollars (a conversion rate of 0.88 was used) divided by 8. In other words, if the WTI was Cdn $ 40 per barrel, the natural gas price would be $ 5 per Mcf. It should be noted that the relationship between natural gas prices and crude oil prices has been rather volatile and therefore higher or lower gas prices could be forecasted.

Also it was assumed that no matter how high the price of natural gas would be, the source of energy would remain natural gas. This is a rather conservative assumption. There is ample evidence that above a price range of $ 5 to $ 7 per Mcf, operators will find it more economic to build gasification plants.

Based on price information of the Department of Energy, it was assumed that the Athabasca bitumen price would be 45% of the WTI price (in Canadian dollars), the Cold Lake heavy oil price would be 60% of the WTI price and the SCO price would be equal to WTI. It should be noted that there is extreme price volatility between bitumen prices and WTI and therefore the above price levels may not reflect the proper value of these products. Based on price information over the last years (which involved high and low WTI prices) it was also assumed that the 45% and 60% percentages would be constant over the entire WTI price range.

There are no specific administrative procedures for determining bitumen values for royalty purposes. Also it does not seem that there are clear independent and objective market indicators that can be used to establish the bitumen value. The above levels of 45% and 60% are subject to great uncertainty. Also whether bitumen values and Cold Lake values for royalty analysis purposes should be based on a percentage of WTI or a more complex formula seems unclear.

All costs were escalated with 2% per year. All fiscal calculations were done based on nominal dollars. Subsequently, all results were represented in 2007 real dollars by discounting for an assumed 2% inflation rate.

2.3. Generic fiscal system.

The generic fiscal system as described in Technical Royalty Report # 1 was used.

For payout calculation purposes a long term bond rate of 6% was used in nominal terms. The current combined corporate income tax rate of 30% was used. The generic fiscal system was applied to the production operations and as a result royalties were based on the bitumen prices.

For the Suncor and Syncrude terms the generic fiscal system was applied using the SCO prices.

For this initial simplified analysis, the Alberta terms do not include bonuses, rentals or property taxes. Rentals and property taxes do not affect the results in a material manner, while bonuses are a voluntary component of the fiscal terms, determined entirely by the investor.

3. ECONOMIC-FISCAL EVALUATION – INVESTOR PERSPECTIVE

3.1. Profitability indicators

A variety of profitability indicators will be used to analyze the profitability of oil sands ventures. All profitability criteria are based on cash flows in real values (2007 Canadian dollars).

It should be noted that the following economics are "un-risked" economics. In other words, the modest risk associated with the fact that the project may be abandoned, due to deteriorating economic circumstances, after the initial evaluation, is not separately evaluated in this report. Also, in particular under SAGD projects, the oil recovery rate is subject to much uncertainty. The probability distribution of project results depending on more or less favorable recovery of oil or upgrading results is not considered in this analysis.

The four profitability indicators used for evaluation will be reviewed below.

Internal Rate of Return (IRR)

The internal rate of return on a cash flow basis (IRR) illustrates how fast profits are being made and the attractiveness of the cash flow relative to the initial investment.

Net Present Value discounted at 10% (NPV @10% or NPV10)

The net present value discounted at 10% per year (NPV@10% or NPV10) illustrates the present value of a project. It is a good indicator of the total amount of profits that is being made with the venture. The 10% discount rate is a widely used international discount rate. This rate reflects the cost of capital plus a "safety" margin for project evaluation. The absolute size of the NPV10 is primarily a function of the size of the project. Large projects have large NPV10 values and small projects have small values.

Profitability Ratio discounted at 10% (PFR @10% or PFR10)

The profitability ratio discounted at 10% reflects how effectively the capital is being used in project. The ratio in this report is being determined as follows:

PFR10 = (NPV10 + Total Capital @10%)/(Total Capital @10%)

In order to determine PFR10 the total capital expenditures are also discounted at 10%. The PFR10 indicates the profitability per dollar invested.

Net Present Value @ 10% per barrel equivalent (NPV10/BOE)

The NPV10/BOE makes it possible to compare the NPV10 values of projects around the world, irrespective of whether the projects are small or large. It is an important indicator to reveal which project makes the highest amount of profit per barrel equivalent.

Profitability criteria – general comments

The tables below are color coded. The following color scheme was used:

Black	- the project has an IRR of less than 5% in real terms.
Red	- the project is typically unacceptable to the investor
Green	- the project is typically acceptable to the investor
Blue	- the project is attractive to the investor
Yellow ("Gold")	- the project is very attractive to the investor

It should be noted that "acceptable" or "attractive" are used here in a overall context relative to any other investment opportunity.

Of course, the higher the bitumen or SCO price, the more attractive the investment.

3.2. International comparisons

It is difficult to compare from an investor's perspective Alberta oil sands developments with developments of conventional crude oil resources around the world. The Alberta resources are very different and unique from other oil developments.

<u>*Exploration*</u>

The first difference is, of course, that the Alberta oil sands do not need to be discovered. The resources have already been identified. It is not necessary to have a high risk exploration program to discover the oil as would be the case for most international developments. This makes the risk profile of Alberta oil sands development fundamentally different from most international developments.

There are few other opportunities in the world for developments of oil that has already been discovered. The projects that are most similar in size and nature are the Orinoco heavy oil developments in Venezuela. Also in the former Soviet Union there were a number of oil fields that had already been discovered for which development contracts were concluded, such as the Tengiz oil field in Kazakhstan. Also some countries are offering EOR contracts or opportunities for fields that have already been producing, such as Kern River in California or Duri in Indonesia. Nevertheless, development opportunities for oil that has already been discovered are rare outside Alberta.

Reserve size

Secondly, the individual Alberta projects are of a large size compared to possible international oil field developments. In this report projects of 510 and 1870 million barrels of synthetic crude oil will be discussed. Projects of this size are typical for oil sands developments.

It should be noted that outside Alberta, new development opportunities of crude oil reserves in excess of 500 million barrels are rare. At this time at best about 15 oil projects are currently in development or planned by private investors that are in excess of this size.

Internationally, there are even less new development opportunities of crude oil projects in excess of 2 billion barrels reserves. There are probably no more than 5 projects of this scale existing outside Alberta in current development or planned by private investors.

The Alberta oil sands therefore present a unique opportunity for investors for large scale access to oil resources. The number of projects in excess of 500 million barrels in development or planning stage inside Alberta is probably already more than all similar reserve size opportunities combined that exist for private investors in the rest of the world.

Production profile

The production profile of Alberta oil sands projects is rather different from typical conventional oil projects, such as large deep water oil fields. Most conventional fields start at a relatively high level of production and feature a relatively steep decline curve within a short period of time. Large conventional oil fields may produce as much as 7 – 10% of the reserves in the first year of peak production. In the case of oil sands developments the first year peak production upon the termination of the last development phase is typically 3 – 5% of the reserves. In general, therefore Alberta oil sands projects compared with the development of conventional oil fields (not including exploratory risk):

- have a lower IRR for the same reserve size, and
- have an attractive NPV10 for the same level of peak production.

Many deep water conventional oil projects often require all main floating facilities to be in place at peak production. Alberta oil sands can be developed in several phases with peak production only being achieved after the second or third phase. This permits cost savings and technological adjustments during the second or third phase and lowers the overall project risk. Also the second and third phases are paid for from cash flow and do not require or require only modest "out-of-pocket" investments, since these phases can be financed from the cash flow from the first phase.

Therefore, in general, the capital expenditures at the final peak production for Alberta oil sands are high compared to conventional deep water oil fields. However, the "out-of-pocket" capital expenditures prior to the first production are typically modest or average compared to such fields, as can be seen from the tables in Chapter 2.

Price Sensitivity

On a comparative international basis, of course, higher oil prices make all petroleum investments more attractive. The color coded scheme on the map does not refer to the **relative** attractiveness compared to other international opportunities under the same price assumption. In other words, a cost-price combination could be identified as "very attractive" and colored in yellow on the table. Yet, it might well be that there are international development opportunities that would be more attractive at the same price level.

General Comment

As a result of the above mentioned factors it is difficult to compare Alberta oil sands profitability with other oil projects around the world.

It should also be noted that the attractiveness would be different from company to company. The relative attractiveness of a project depends very much on other projects that companies have under development and the capital and human resources that companies have available for project development.

Nevertheless, in the text some general comments will be made on the international comparative attractiveness where appropriate.

3.3. Real IRR

The following six tables provide the "maps" for the IRR results.

The IRR maps are based on the following assessment:

IRR assessment

< 5%	
< 13%	
< 20%	
< 30%	
> 30%	

IRR < 5%	- black	
IRR < 13%	- red	- unacceptable
IRR < 20%	- green	- acceptable
IRR < 30%	- blue	- attractive
IRR of 30% and higher	- gold	- very attractive

Table 3.1. COLD LAKE
IRR (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				5.26%	9.42%	11.32%	15.67%
30	34.09	$4.26	$20.45	6.40%	8.27%	10.46%	12.99%	17.11%	19.85%	24.89%
40	45.45	$5.68	$27.27	11.83%	13.86%	16.21%	19.00%	23.30%	26.62%	32.22%
50	56.82	$7.10	$34.09	16.32%	18.52%	21.05%	24.09%	28.52%	32.36%	38.41%
60	68.18	$8.52	$40.91	20.23%	22.58%	25.30%	28.52%	33.14%	37.36%	43.86%
70	79.55	$9.94	$47.73	23.76%	26.22%	29.11%	32.52%	37.28%	41.90%	48.70%
80	90.91	$11.36	$54.55	26.94%	29.58%	32.57%	36.13%	41.11%	45.95%	53.15%
90	102.27	$12.78	$61.36	29.92%	32.60%	35.74%	39.51%	44.57%	49.72%	57.26%
100	113.64	$14.20	$68.18	32.63%	35.43%	38.71%	42.62%	47.80%	53.24%	61.01%

Table 3.2. SAGD-ATHABASCA
IRR (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						4.13%	7.91%
30	34.09	$4.26	$15.34				5.70%	8.42%	11.82%	16.20%
40	45.45	$5.68	$20.45	4.78%	6.55%	8.66%	11.14%	14.10%	17.81%	22.69%
50	56.82	$7.10	$25.57	8.81%	10.77%	13.01%	15.65%	18.85%	22.88%	28.12%
60	68.18	$8.52	$30.68	12.32%	14.36%	16.74%	19.56%	22.99%	27.25%	32.90%
70	79.55	$9.94	$35.80	15.42%	17.56%	20.08%	23.08%	26.66%	31.22%	37.16%
80	90.91	$11.36	$40.91	18.24%	20.48%	23.14%	26.23%	30.06%	34.78%	41.10%
90	102.27	$12.78	$46.02	20.80%	23.19%	25.91%	29.18%	33.13%	38.09%	44.64%
100	113.64	$14.20	$51.14	23.22%	25.65%	28.50%	31.91%	36.00%	41.21%	47.95%

Table 3.3. SAGD-ATHABASCA+UPGR
IRR (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23							6.76%
30	34.09	$4.26	$15.34				5.93%	7.79%	10.00%	12.67%
40	45.45	$5.68	$20.45	5.52%	6.85%	8.35%	10.06%	12.03%	14.39%	17.31%
50	56.82	$7.10	$25.57	8.70%	10.10%	11.66%	13.46%	15.57%	18.11%	21.26%
60	68.18	$8.52	$30.68	11.42%	12.87%	14.52%	16.43%	18.68%	21.39%	24.78%
70	79.55	$9.94	$35.80	13.82%	15.34%	17.08%	19.10%	21.47%	24.36%	27.95%
80	90.91	$11.36	$40.91	16.01%	17.60%	19.43%	21.54%	24.06%	27.08%	30.87%
90	102.27	$12.78	$46.02	18.02%	19.69%	21.59%	23.81%	26.43%	29.60%	33.57%
100	113.64	$14.20	$51.14	19.91%	21.63%	23.62%	25.93%	28.66%	31.98%	36.09%

Table 3.4. MINE-ATHABASCA
IRR (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						5.97%	9.80%
30	34.09	$4.26	$15.34			5.43%	7.66%	10.36%	13.72%	18.12%
40	45.45	$5.68	$20.45	6.75%	8.55%	10.64%	13.08%	16.05%	19.77%	24.70%
50	56.82	$7.10	$25.57	10.80%	12.73%	14.96%	17.61%	20.83%	24.90%	30.31%
60	68.18	$8.52	$30.68	14.29%	16.34%	18.74%	21.60%	25.04%	29.45%	35.19%
70	79.55	$9.94	$35.80	17.40%	19.58%	22.14%	25.14%	28.86%	33.47%	39.60%
80	90.91	$11.36	$40.91	20.25%	22.56%	25.22%	28.44%	32.28%	37.18%	43.54%
90	102.27	$12.78	$46.02	22.89%	25.27%	28.08%	31.42%	35.46%	40.55%	47.22%
100	113.64	$14.20	$51.14	25.32%	27.83%	30.76%	34.21%	38.45%	43.67%	50.52%

Table 3.5. MINE-ATHABASCA-UPGRADER
IRR (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						6.60%	9.80%
30	34.09	$4.26	$15.34			6.04%	7.91%	10.17%	12.99%	16.74%
40	45.45	$5.68	$20.45	7.10%	8.60%	10.34%	12.40%	14.91%	18.10%	22.37%
50	56.82	$7.10	$25.57	10.45%	12.07%	13.96%	16.21%	18.98%	22.51%	27.26%
60	68.18	$8.52	$30.68	13.37%	15.11%	17.15%	19.61%	22.61%	26.46%	31.59%
70	79.55	$9.94	$35.80	16.00%	17.86%	20.06%	22.67%	25.92%	30.02%	35.52%
80	90.91	$11.36	$40.91	18.42%	20.41%	22.72%	25.53%	28.95%	33.32%	39.11%
90	102.27	$12.78	$46.02	20.68%	22.76%	25.22%	28.16%	31.77%	36.36%	42.46%
100	113.64	$14.20	$51.14	22.79%	24.99%	27.57%	30.64%	34.43%	39.21%	45.54%

Table 3.6. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
IRR (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						6.18%	9.23%
30	34.09	$4.26	$15.34			5.67%	7.44%	9.59%	12.31%	15.90%
40	45.45	$5.68	$20.45	6.67%	8.10%	9.77%	11.74%	14.15%	17.21%	21.29%
50	56.82	$7.10	$25.57	9.87%	11.43%	13.24%	15.41%	18.07%	21.43%	25.96%
60	68.18	$8.52	$30.68	12.68%	14.35%	16.31%	18.66%	21.53%	25.20%	30.14%
70	79.55	$9.94	$35.80	15.20%	16.99%	19.09%	21.60%	24.69%	28.66%	33.89%
80	90.91	$11.36	$40.91	17.52%	19.42%	21.66%	24.32%	27.60%	31.79%	37.36%
90	102.27	$12.78	$46.02	19.69%	21.70%	24.04%	26.85%	30.33%	34.71%	40.57%
100	113.64	$14.20	$51.14	21.74%	23.82%	26.27%	29.25%	32.85%	37.46%	43.54%

Generic system based on bitumen values

As can be easily seen from the above maps the IRR is highly sensitive to price and cost conditions. This is to be expected. Under low prices and high costs the IRR is unacceptable. Under high prices and low costs the IRR is very attractive.

Table 3.1 illustrates the Cold Lake SAGD conditions and Table 3.2 the Athabasca SAGD. These two tables illustrate how important the bitumen price is for the economic attractiveness of the upstream production ventures. Cold Lake is set at 60% of WTI and Athabasca SAGD is set at 45% of WTI. Therefore, the IRR on Athabasca SAGD is much less attractive that for the Cold Lake SAGD.

Under a WTI of US $ 20 per barrel for Cold Lake and US $ 30 per barrel for Athabasca oil sands, developments have unacceptable profitability under most of the current cost range, except for low cost conditions.

Obviously, the WTI price was at $ 20 or less a decade ago. The cost levels of past oil sands developments, even adjusted for inflation, must have been below Cost-1 in order to make these developments attractive. These historical costs merit further investigation.

However, under the cost range of today a drop in oil prices to US $ 20 per barrel WTI or below would be negative for the oil sands economics.

Even at US $ 30 per barrel many developments would have an unattractive profitability.

This indicates that oil sands developments under current cost conditions remain subject to considerable down side price risk.

Under current Cost-3 or Cost-4 conditions, it seems that a price level of US $ 40 per barrel WTI creates about minimum acceptable IRR levels. Large integrated mining operations perform somewhat better than small SAGD projects with upgrading. This is due to the “economy of scale” that was assumed in this report for the cost ranges.

At higher price levels the IRR becomes rapidly attractive or very attractive, even under relatively high cost conditions.

The current high level of investment in Alberta therefore seems to indicate that most investors work with price forecasts that are US $ 40 per barrel WTI or higher.

The IRR with upgrading is only modestly less than without upgrading. This is due to the fact that bitumen prices are very low at 45% of WTI. The production capex and upgrading capex are not very different, with proper allocation of common costs. Therefore, the overall relationship between revenues and costs is not very different for the production and upgrading components and IRR with or without upgrading is similar.

Generic system based on SCO values

An interesting observation that can be made is that the difference in IRR between basing the royalty on SCO or bitumen values is not as significant as one would expect, as can be seen from comparing Tables 3.5 and 3.6. Going to bitumen values seems to improve the IRR with about 1% to 2%.

Comparison with international projects

Compared to other large international oil development schemes, in particular deep water field developments, the IRR for oil sands developments is not unusually high for high prices or low cost conditions. Many large oil development opportunities in the world would have an IRR of 25% or more at US $ 60 WTI. In fact, the IRR for oil sands developments is often less than the IRR for international conventional oil development opportunities of comparable scale.

Under low oil prices, large international crude oil development opportunities are usually more profitable that oil sands developments. Therefore, down side price risk is less for comparable international opportunities.

3.4. Real PFR10

The following six tables provide the “maps” for the PFR10 results. On the maps the area is always indicated in black if the IRR is less than 5%

The PFR10 maps are based on the following assessment:

PFR10 assessment

IRR<5%
< 1.15
< 1.75
< 2.50
> 2.50

IRR	< 5%	- black	
PFR10	< 1.15	- red	- unacceptable
PFR10	< 1.75	- green	- acceptable
PFR10	< 2.50	- blue	- attractive
PFR10 of 2.50 and higher		- gold	- very attractive

Table 3.7. COLD LAKE
PFR10 (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				0.77	0.97	1.07	1.31
30	34.09	$4.26	$20.45	0.83	0.92	1.02	1.16	1.40	1.57	1.93
40	45.45	$5.68	$27.27	1.09	1.20	1.34	1.52	1.81	2.07	2.56
50	56.82	$7.10	$34.09	1.35	1.48	1.65	1.87	2.23	2.57	3.18
60	68.18	$8.52	$40.91	1.60	1.76	1.97	2.23	2.64	3.07	3.80
70	79.55	$9.94	$47.73	1.85	2.04	2.28	2.58	3.06	3.56	4.42
80	90.91	$11.36	$54.55	2.10	2.32	2.59	2.94	3.47	4.06	5.04
90	102.27	$12.78	$61.36	2.35	2.59	2.90	3.29	3.88	4.55	5.66
100	113.64	$14.20	$68.18	2.60	2.87	3.21	3.65	4.30	5.05	6.28

Table 3.8. SAGD-ATHABASCA
PFR10 (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64						0.72	0.90
30	34.09	$4.26	$20.45				0.79	0.92	1.09	1.34
40	45.45	$5.68	$27.27	0.75	0.83	0.93	1.06	1.22	1.44	1.77
50	56.82	$7.10	$34.09	0.94	1.04	1.16	1.31	1.51	1.78	2.20
60	68.18	$8.52	$40.91	1.12	1.23	1.37	1.55	1.79	2.12	2.62
70	79.55	$9.94	$47.73	1.29	1.42	1.59	1.80	2.08	2.46	3.05
80	90.91	$11.36	$54.55	1.47	1.62	1.80	2.04	2.36	2.80	3.47
90	102.27	$12.78	$61.36	1.64	1.81	2.02	2.28	2.64	3.14	3.90
100	113.64	$14.20	$68.18	1.81	2.00	2.23	2.53	2.93	3.48	4.32

Table 3.9 SAGD-ATHABASCA+UPGR
PFR10 (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64							0.80
30	34.09	$4.26	$20.45				0.76	0.86	1.00	1.19
40	45.45	$5.68	$27.27	0.74	0.81	0.90	1.00	1.14	1.32	1.56
50	56.82	$7.10	$34.09	0.92	1.01	1.11	1.24	1.41	1.63	1.94
60	68.18	$8.52	$40.91	1.09	1.20	1.32	1.48	1.68	1.94	2.31
70	79.55	$9.94	$47.73	1.27	1.39	1.53	1.72	1.95	2.26	2.69
80	90.91	$11.36	$54.55	1.44	1.58	1.74	1.95	2.22	2.57	3.07
90	102.27	$12.78	$61.36	1.61	1.77	1.95	2.19	2.49	2.88	3.44
100	113.64	$14.20	$68.18	1.79	1.96	2.16	2.42	2.76	3.20	3.82

Table 3.10 MINE-ATHABASCA
PFR10 (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64						0.78	0.99
30	34.09	$4.26	$20.45			0.75	0.87	1.02	1.23	1.54
40	45.45	$5.68	$27.27	0.82	0.92	1.04	1.19	1.39	1.66	2.07
50	56.82	$7.10	$34.09	1.05	1.17	1.31	1.50	1.75	2.09	2.61
60	68.18	$8.52	$40.91	1.27	1.41	1.58	1.81	2.10	2.52	3.14
70	79.55	$9.94	$47.73	1.48	1.65	1.85	2.11	2.46	2.94	3.67
80	90.91	$11.36	$54.55	1.70	1.89	2.12	2.42	2.82	3.37	4.20
90	102.27	$12.78	$61.36	1.91	2.12	2.39	2.72	3.17	3.80	4.74
100	113.64	$14.20	$68.18	2.13	2.36	2.65	3.03	3.53	4.22	5.27

Table 3.11. MINE-ATHABASCA-UPGRADER
PFR10 (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64						0.79	0.99
30	34.09	$4.26	$20.45			0.76	0.87	1.01	1.21	1.50
40	45.45	$5.68	$27.27	0.82	0.91	1.02	1.16	1.35	1.61	2.00
50	56.82	$7.10	$34.09	1.03	1.14	1.28	1.46	1.69	2.02	2.51
60	68.18	$8.52	$40.91	1.23	1.37	1.53	1.75	2.03	2.42	3.01
70	79.55	$9.94	$47.73	1.44	1.59	1.79	2.03	2.36	2.82	3.52
80	90.91	$11.36	$54.55	1.64	1.82	2.04	2.32	2.70	3.23	4.02
90	102.27	$12.78	$61.36	1.84	2.04	2.29	2.61	3.04	3.63	4.52
100	113.64	$14.20	$68.18	2.04	2.27	2.54	2.90	3.37	4.03	5.03

Table 3.12. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
PFR10 (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64						0.77	0.95
30	34.09	$4.26	$20.45			0.75	0.85	0.97	1.15	1.41
40	45.45	$5.68	$27.27	0.80	0.88	0.99	1.11	1.28	1.51	1.85
50	56.82	$7.10	$34.09	0.99	1.09	1.21	1.37	1.58	1.87	2.30
60	68.18	$8.52	$40.91	1.18	1.29	1.44	1.63	1.87	2.22	2.74
70	79.55	$9.94	$47.73	1.36	1.49	1.66	1.88	2.17	2.58	3.18
80	90.91	$11.36	$54.55	1.54	1.69	1.89	2.13	2.46	2.93	3.62
90	102.27	$12.78	$61.36	1.71	1.89	2.11	2.39	2.76	3.28	4.06
100	113.64	$14.20	$68.18	1.89	2.09	2.33	2.64	3.05	3.63	4.50

Generic system based on bitumen values

As with the IRR, the PFR10 is very sensitive to the level of costs and prices.

At a price of US $30 per barrel WTI or lower the PFR10 is typically unattractive, except for combinations with low cost levels.

At US $ 40 per barrel WTI, the oil sands developments become typically "acceptable" to "attractive" for Cost-4 or lower. Cold Lake developments become largely attractive or even very attractive. The economy of scale of the mining operations with or without upgrading results provides somewhat better profitability for the PFR10 than small SAGD operations.

Over US $ 40 per barrel, the PFR10 becomes rapidly quite profitable, in particular for mining based operations and Cold Lake investments.

The PFR10 shows stronger profitability than the IRR. This is logical. At a 10% discount rate the large cumulative production creates a strong NPV10. The stable ongoing production for almost three decades results in a considerable value. At the same time the discounted capital expenditures make the ratio attractive.

The PFR10 also shows the higher attractiveness of the Cold Lake deposits compared with Athabasca bitumen, due to the higher bitumen values in Cold Lake.

Again the difference in profitability with upgrading or without upgrading is modest.

Generic system based on SCO values

The switch to bitumen values under the Suncor/Syncrude terms provide for only a modest increase in PFR10 values.

Comparison with international projects

Compared to international large conventional oil development projects, the PFR10 is not unusual for the price and cost range. Many international projects would have a PFR10 above 2.00 at US $ 60 per barrel WTI. Nevertheless, the PFR10 compares reasonably well with such development projects under such prices.

At low prices the PFR10 is for oil sands is much less than large scale international development opportunities and therefore down side price risk is much higher for oil sands developments.

3.5. Real NPV10

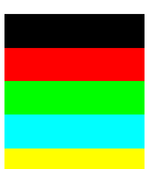
As described in the introduction to this chapter, the NPV10 is strongly related to the size of the project. It is therefore, not possible to compare different size projects on this basis.

Nevertheless, it is very interesting to have a discussion of NPV10 values, since the large oil sands mining operations occupy a rather unique economic position in this respect in the world.

For discussion purposes, the following scale will be used:

NPV10 assessment

IRR<5%
< 100
< 500
< 1500
> 1500



IRR < 5% - black
NPV10 < $ 100 million - red
NPV10 < $ 500 million - green
NPV10 < $ 1500 million - blue
NPV10 over $ 1500 million - gold

The following tables provide the NPV10 maps:

Table 3.13. COLD LAKE
NPV10 ($ million) (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				-$220	-$24	$47	$172
30	34.09	$4.26	$20.45	-$241	-$106	$26	$152	$331	$399	$521
40	45.45	$5.68	$27.27	$131	$256	$380	$504	$681	$747	$869
50	56.82	$7.10	$34.09	$485	$609	$730	$853	$1,028	$1,095	$1,214
60	68.18	$8.52	$40.91	$835	$957	$1,079	$1,199	$1,375	$1,440	$1,561
70	79.55	$9.94	$47.73	$1,184	$1,305	$1,426	$1,547	$1,721	$1,788	$1,906
80	90.91	$11.36	$54.55	$1,531	$1,654	$1,773	$1,893	$2,068	$2,133	$2,252
90	102.27	$12.78	$61.36	$1,880	$1,999	$2,119	$2,239	$2,414	$2,478	$2,599
100	113.64	$14.20	$68.18	$2,225	$2,345	$2,464	$2,586	$2,759	$2,824	$2,944

Table 3.14. SAGD-ATHABASCA
NPV10 ($ million) (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						-$194	-$57
30	34.09	$4.26	$15.34				-$200	-$65	$65	$190
40	45.45	$5.68	$20.45	-$346	-$208	-$73	$57	$183	$307	$430
50	56.82	$7.10	$25.57	-$81	$49	$176	$300	$424	$547	$667
60	68.18	$8.52	$30.68	$167	$292	$416	$540	$663	$783	$905
70	79.55	$9.94	$35.80	$410	$533	$656	$779	$900	$1,022	$1,141
80	90.91	$11.36	$40.91	$651	$772	$896	$1,016	$1,139	$1,258	$1,379
90	102.27	$12.78	$46.02	$889	$1,012	$1,133	$1,254	$1,375	$1,495	$1,615
100	113.64	$14.20	$51.14	$1,129	$1,249	$1,370	$1,492	$1,612	$1,733	$1,852

Table 3.15. SAGD-ATHABASCA+UPGR
NPV10 ($ million) (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23							-$294
30	34.09	$4.26	$15.34				-$574	-$284	$0	$279
40	45.45	$5.68	$20.45	-$856	-$564	-$275	$9	$289	$567	$844
50	56.82	$7.10	$25.57	-$266	$19	$300	$578	$856	$1,132	$1,407
60	68.18	$8.52	$30.68	$309	$588	$866	$1,144	$1,421	$1,695	$1,971
70	79.55	$9.94	$35.80	$878	$1,154	$1,432	$1,709	$1,983	$2,259	$2,533
80	90.91	$11.36	$40.91	$1,444	$1,720	$1,997	$2,272	$2,548	$2,821	$3,096
90	102.27	$12.78	$46.02	$2,008	$2,285	$2,560	$2,835	$3,110	$3,384	$3,658
100	113.64	$14.20	$51.14	$2,574	$2,848	$3,122	$3,399	$3,672	$3,948	$4,220

Table 3.16. MINE-ATHABASCA
NPV10 ($ million) (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						-$540	-$22
30	34.09	$4.26	$15.34			-$976	-$448	$62	$555	$1,037
40	45.45	$5.68	$20.45	-$879	-$360	$145	$637	$1,123	$1,599	$2,072
50	56.82	$7.10	$25.57	$228	$721	$1,206	$1,688	$2,162	$2,635	$3,106
60	68.18	$8.52	$30.68	$1,292	$1,774	$2,254	$2,731	$3,198	$3,670	$4,134
70	79.55	$9.94	$35.80	$2,338	$2,816	$3,294	$3,761	$4,234	$4,698	$5,164
80	90.91	$11.36	$40.91	$3,379	$3,857	$4,324	$4,798	$5,262	$5,728	$6,191
90	102.27	$12.78	$46.02	$4,420	$4,887	$5,355	$5,826	$6,290	$6,757	$7,222
100	113.64	$14.20	$51.14	$5,450	$5,917	$6,390	$6,854	$7,323	$7,783	$8,248

Table 3.17. MINE-ATHABASCA-UPGRADER
NPV10 ($ million) (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						-$1,078	-$53
30	34.09	$4.26	$15.34			-$1,984	-$950	$68	$1,068	$2,057
40	45.45	$5.68	$20.45	-$1,852	-$825	$187	$1,186	$2,179	$3,163	$4,143
50	56.82	$7.10	$25.57	$305	$1,307	$2,298	$3,287	$4,269	$5,250	$6,227
60	68.18	$8.52	$30.68	$2,420	$3,410	$4,397	$5,381	$6,356	$7,335	$8,305
70	79.55	$9.94	$35.80	$4,517	$5,503	$6,487	$7,462	$8,442	$9,413	$10,387
80	90.91	$11.36	$40.91	$6,608	$7,594	$8,568	$9,549	$10,520	$11,493	$12,463
90	102.27	$12.78	$46.02	$8,700	$9,674	$10,649	$11,628	$12,599	$13,573	$14,546
100	113.64	$14.20	$51.14	$10,780	$11,755	$12,735	$13,706	$14,682	$15,649	$16,622

Table 3.18. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
NPV10 ($ million) (real, 2007 Cdn $)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						-$1,163	-$196
30	34.09	$4.26	$15.34			-$2,096	-$1,113	-$156	$775	$1,686
40	45.45	$5.68	$20.45	-$2,040	-$1,070	-$119	$812	$1,730	$2,631	$3,523
50	56.82	$7.10	$25.57	-$81	$853	$1,770	$2,685	$3,585	$4,468	$5,353
60	68.18	$8.52	$30.68	$1,813	$2,726	$3,631	$4,530	$5,415	$6,300	$7,182
70	79.55	$9.94	$35.80	$3,674	$4,576	$5,475	$6,363	$7,247	$8,133	$8,999
80	90.91	$11.36	$40.91	$5,521	$6,420	$7,312	$8,194	$9,069	$9,950	$10,817
90	102.27	$12.78	$46.02	$7,365	$8,261	$9,141	$10,016	$10,901	$11,768	$12,642
100	113.64	$14.20	$51.14	$9,209	$10,088	$10,962	$11,852	$12,718	$13,585	$14,456

Generic system based on bitumen values

For cost-price combinations with an IRR of less than 10%, the NPV10 will be negative, by definition.

Also for the NPV10 it is clear that oil sands developments are typically unattractive at prices of US $ 30 per barrel WTI or less. However, it is interesting to see how Mine+Upgrading projects at Cost-2 or Cost-1 level already produce very interesting NPV10 values at a price of US $ 30 per barrel WTI.

For higher prices, it becomes immediately obvious that the NPV10 depends on the size of the project and on the prices that are being obtained.

Cold Lake projects are more attractive than Athabasca SAGD projects because the price for the bitumen (heavy oil) is higher in Cold Lake.

Large mining projects have a higher NPV10 than the smaller SAGD projects. Projects with upgrading have a higher NPV10 than projects without upgrading.

The Mine+Upgrading projects have the highest NPV10 values.

A very important characteristic of the Mine+Upgrading projects is that the NPV10 is very high in absolute terms. At US $ 50 or $ 60 per barrel WTI and for the cost range of Cost 4 – Cost 2, NPV10 values range from $ 3.3 to $ 7.3 billion.

Generic system based on SCO values

The switch to bitumen values from SCO values in Suncor/Syncrude terms, will add very considerable NPV10 to the projects. Depending on price and cost conditions, the switch to bitumen pricing could add as much as $ 1 billion or more to the NPV10 of a project. The benefit increases with higher oil prices than $ 60 per barrel WTI.

Comparison with international projects

It should be noted that there are few development projects in the world with such high NPV10 values, at any project size, at a WTI price of US $ 60 per barrel. Large Mine+Upgrading projects are therefore enormous long term value creators for the investors, once oil prices exceed $ 40 per barrel WTI and based on average or low costs. Value creation is particularly strong when investors manage to maintain costs in the Cost-3 range or less.

The main driver for the strong level of investment in Alberta in oil sands developments and the related upgrading facilities is therefore a very significant NPV10 value creation for the investors.

NPV10 value of upgrading

What is also of great significance is that the NPV10 values double as a result of upgrading. This can be analyzed by comparing SAGD with SAGD+Upgrading or Mine with Mine+Upgrading. In other words, upgrading adds enormous NPV10 value to the projects and therefore to the value of Alberta production.

This also makes it clear that the upgrading value is part of the inherent value of the resource on an SCO value basis or an important “associated value” on a bitumen value basis. Upgrading is clearly not a utility type operation that makes an IRR in the 10% range in real terms on total capital. If upgrading would be such a utility type operation the NPV10 value of the upgrading cash flow would be zero by definition and the production NPV10 prior to upgrading would be double.

3.6. Real NPV10/BOE

The NPV10/BOE maps provide an interesting inside in the NPV10 on a per barrel basis.

The NPV10/BOE maps are based on the following assessment:

NPV10/BOE assessment

IRR<5%
< 0.33
< 1.50
< 3.00
> 3.00

IRR	< 5%	- black	
NPV10/BOE	< $ 0.33	- red	- unacceptable
NPV10/BOE	< $ 1.50	- green	- acceptable
NPV10/BOE	< $ 3.00	- blue	- attractive
NPV10/BOE of $ 3.00 and higher		- gold	- very attractive

Tables 3.19 through 3.24 provide the overview.

Table 3.19. COLD LAKE
NPV10/SCO bbl

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				-$0.43	-$0.05	$0.09	$0.34
30	34.09	$4.26	$20.45	-$0.47	-$0.21	$0.05	$0.30	$0.65	$0.78	$1.02
40	45.45	$5.68	$27.27	$0.26	$0.50	$0.75	$0.99	$1.34	$1.47	$1.70
50	56.82	$7.10	$34.09	$0.95	$1.19	$1.43	$1.67	$2.02	$2.15	$2.38
60	68.18	$8.52	$40.91	$1.64	$1.88	$2.12	$2.35	$2.70	$2.82	$3.06
70	79.55	$9.94	$47.73	$2.32	$2.56	$2.80	$3.03	$3.37	$3.51	$3.74
80	90.91	$11.36	$54.55	$3.00	$3.24	$3.48	$3.71	$4.06	$4.18	$4.42
90	102.27	$12.78	$61.36	$3.69	$3.92	$4.15	$4.39	$4.73	$4.86	$5.10
100	113.64	$14.20	$68.18	$4.36	$4.60	$4.83	$5.07	$5.41	$5.54	$5.77

Table 3.20. SAGD-ATHABASCA
NPV10/SCO bbl

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-$0.38	-$0.11
30	34.09	$4.26	$15.34	[redacted]	[redacted]	[redacted]	-$0.39	-$0.13	$0.13	$0.37
40	45.45	$5.68	$20.45	-$0.68	-$0.41	-$0.14	$0.11	$0.36	$0.60	$0.84
50	56.82	$7.10	$25.57	-$0.16	$0.10	$0.34	$0.59	$0.83	$1.07	$1.31
60	68.18	$8.52	$30.68	$0.33	$0.57	$0.82	$1.06	$1.30	$1.54	$1.77
70	79.55	$9.94	$35.80	$0.80	$1.04	$1.29	$1.53	$1.76	$2.00	$2.24
80	90.91	$11.36	$40.91	$1.28	$1.51	$1.76	$1.99	$2.23	$2.47	$2.70
90	102.27	$12.78	$46.02	$1.74	$1.99	$2.22	$2.46	$2.70	$2.93	$3.17
100	113.64	$14.20	$51.14	$2.21	$2.45	$2.69	$2.93	$3.16	$3.40	$3.63

Table 3.21. SAGD-ATHABASCA+UPGR
NPV10/SCO bbl

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-$0.58
30	34.09	$4.26	$15.34	[redacted]	[redacted]	[redacted]	-$1.13	-$0.56	$0.00	$0.55
40	45.45	$5.68	$20.45	-$1.68	-$1.11	-$0.54	$0.02	$0.57	$1.11	$1.65
50	56.82	$7.10	$25.57	-$0.52	$0.04	$0.59	$1.13	$1.68	$2.22	$2.76
60	68.18	$8.52	$30.68	$0.61	$1.15	$1.70	$2.24	$2.79	$3.32	$3.86
70	79.55	$9.94	$35.80	$1.72	$2.26	$2.81	$3.35	$3.89	$4.43	$4.97
80	90.91	$11.36	$40.91	$2.83	$3.37	$3.92	$4.45	$5.00	$5.53	$6.07
90	102.27	$12.78	$46.02	$3.94	$4.48	$5.02	$5.56	$6.10	$6.63	$7.17
100	113.64	$14.20	$51.14	$5.05	$5.58	$6.12	$6.66	$7.20	$7.74	$8.28

Table 3.22. MINE-ATHABASCA
NPV10/SCO bbl

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-$0.29	-$0.01
30	34.09	$4.26	$15.34	[redacted]	[redacted]	-$0.52	-$0.24	$0.03	$0.30	$0.55
40	45.45	$5.68	$20.45	-$0.47	-$0.19	$0.08	$0.34	$0.60	$0.86	$1.11
50	56.82	$7.10	$25.57	$0.12	$0.39	$0.64	$0.90	$1.16	$1.41	$1.66
60	68.18	$8.52	$30.68	$0.69	$0.95	$1.21	$1.46	$1.71	$1.96	$2.21
70	79.55	$9.94	$35.80	$1.25	$1.51	$1.76	$2.01	$2.26	$2.51	$2.76
80	90.91	$11.36	$40.91	$1.81	$2.06	$2.31	$2.57	$2.81	$3.06	$3.31
90	102.27	$12.78	$46.02	$2.36	$2.61	$2.86	$3.12	$3.36	$3.61	$3.86
100	113.64	$14.20	$51.14	$2.91	$3.16	$3.42	$3.67	$3.92	$4.16	$4.41

Table 3.23. MINE-ATHABASCA-UPGRADER
NPV10/SCO bbl

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23	[redacted]	[redacted]	[redacted]	-$1.73	-$1.14	-$0.58	-$0.03
30	34.09	$4.26	$15.34	-$2.21	-$1.63	-$1.06	-$0.51	$0.04	$0.57	$1.10
40	45.45	$5.68	$20.45	-$0.99	-$0.44	$0.10	$0.63	$1.17	$1.69	$2.22
50	56.82	$7.10	$25.57	$0.16	$0.70	$1.23	$1.76	$2.28	$2.81	$3.33
60	68.18	$8.52	$30.68	$1.29	$1.82	$2.35	$2.88	$3.40	$3.92	$4.44
70	79.55	$9.94	$35.80	$2.42	$2.94	$3.47	$3.99	$4.51	$5.03	$5.55
80	90.91	$11.36	$40.91	$3.53	$4.06	$4.58	$5.11	$5.63	$6.15	$6.66
90	102.27	$12.78	$46.02	$4.65	$5.17	$5.69	$6.22	$6.74	$7.26	$7.78
100	113.64	$14.20	$51.14	$5.76	$6.29	$6.81	$7.33	$7.85	$8.37	$8.89

Table 3.24. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
NPV10/SCO bbl

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						-$0.62	-$0.10
30	34.09	$4.26	$15.34			-$1.12	-$0.60	-$0.08	$0.41	$0.90
40	45.45	$5.68	$20.45	-$1.09	-$0.57	-$0.06	$0.43	$0.93	$1.41	$1.88
50	56.82	$7.10	$25.57	-$0.04	$0.46	$0.95	$1.44	$1.92	$2.39	$2.86
60	68.18	$8.52	$30.68	$0.97	$1.46	$1.94	$2.42	$2.90	$3.37	$3.84
70	79.55	$9.94	$35.80	$1.96	$2.45	$2.93	$3.40	$3.88	$4.35	$4.81
80	90.91	$11.36	$40.91	$2.95	$3.43	$3.91	$4.38	$4.85	$5.32	$5.78
90	102.27	$12.78	$46.02	$3.94	$4.42	$4.89	$5.36	$5.83	$6.29	$6.76
100	113.64	$14.20	$51.14	$4.92	$5.39	$5.86	$6.34	$6.80	$7.26	$7.73

Generic systems based on bitumen values

As can be expected, the profitability indicator NPV10/BOE indicates that at a WTI price of US $ 30 per barrel or less, the oil sands developments are under the current cost range largely unattractive.

At US $ 40 per barrel WTI the projects with Cost-4 or lower become acceptable or attractive.

Over US $ 50 per barrel WTI projects are typically attractive or very attractive.

Generic system based on SCO values

The switch from SCO values to bitumen values for the Suncor and Syncrude projects will add significantly to the NPV10/BOE.

Comparison with international projects

On a NPV10/BOE basis, the upgraded project certainly compare reasonably with international large conventional oil development projects. At US $ 60 WTI many large crude oil development projects will have an NPV10/BOE of $ 2 per barrel or more.

NPV10/BOE value of upgrading

The great importance of upgrading is also illustrated on an NPV10/BOE basis. Upgrading doubles the NPV10/BOE values.

4. ECONOMIC-FISCAL EVALUATION – GOVERNMENT PERSPECTIVE

4.1. Attractiveness Indicators

Four attractiveness indicators from a government perspective will be used in this report.

These indicators will be based on real cash flows in 2007 Canadian dollars. As explained before, the real cash flows were derived from nominal cash flows and therefore the government revenues are being initially determined on the basis of nominal results which are then converted to real results using a 2% inflation rate assumption.

The following four indicators will be used:

Royalty in percent of the gross value of the bitumen

The royalty is expressed as a percentage of the gross value of the bitumen. In other words the royalties, which are calculated on the net income are converted to royalties based on gross income in order to make comparisons with international royalties easier. To facilitate comparisons, this is also done for Mine+Upgrading for the current Suncor and Syncrude terms. In this last case the values of the royalties derived from the synthetic crude oil will be entirely allocated to the lower total gross value of the bitumen.

Royalty in percent of the gross value of synthetic crude oil

The royalty is expressed as a percentage of the value of the synthetic crude oil based on the project. To facilitate comparisons, this is also done for Cold Lake. The royalty percentage is corrected for the volume loss in producing synthetic crude which in this study is assumed to be 15%. As an example, the minimum royalty on bitumen production is 1% of the bitumen value. However, the bitumen value is 45% of the SCO value. This therefore creates a royalty of 0.45%. However, as a result of the 15% volume loss the royalty is actually 0.45% divided by 0.85 of the SCO barrel or 0.5294%

Undiscounted government take

The government take is based on the “divisible income”. The divisible income is the gross value of the production less all expenditures (capital and operating). The divisible income is the income that can be divided between the investor and government.

The government take is the percentage that the total government revenues represent of the divisible income for the project. In formula form:

$$GT = \frac{\text{Government Revenues}}{\text{Gross Revenues - Costs}} \times 100\%$$

The government revenues refer to all revenues to all governments. In the case of Alberta this relates to the income of the province of Alberta and the Federal Government. Where property taxes are collected by municipalities, it also includes municipal income.

The revenues to government includes all payments, such as bonuses, rentals, royalties, corporate income tax, profit shares, production shares, etc. However, as explained before, the Alberta economic-fiscal comparisons do not include, for the moment, bonuses, rentals or property taxes.

The government take on bitumen production is determined on the basis of the gross revenues of the bitumen. The government take on the SCO production of projects including upgrading is determined on the basis of the gross revenues from SCO production.

Discounted government take @ 5%

The discounted government take at a discount factor of 5 % provides better comparative information about when the government revenues are being received. The 5% discount factor is selected on the assumption that the provincial "time value of money" is about 5%. For relatively rich jurisdictions such as Alberta this represents approximately the cost of borrowing.

General comment

The color coding of the maps will be done from an investor perspective. In general, the concept will be used that "gold" represents a low royalty or government take from an international perspective, "green" an average royalty or government take from an international perspective and "magenta" a high royalty or government take from an international perspective. The more detailed calibrations are explained below.

4.2. Bitumen versus SCO comparisons

Chapter 3 provides abundant evidence that the upgrading of the bitumen production adds a considerable NPV10 and NPV10/BOE to the total project. It is therefore clear that upgrading in not merely a utility type operation.

Upgrading is a process that is integral to creating attractive total project value. It seems that the NPV10 of a project is derived by about half from the production operations and half from upgrading operations.

In this context it is entirely reasonable from a government perspective to consider the gross revenues as a result of upgrading as part of the resource revenues that the government should evaluate for royalty and government take purposes. Nevertheless, alternatively, royalty values could also be determined based on bitumen values as is contemplated under the generic system.

The analysis of the royalty income is therefore done on the basis of bitumen values as well as synthetic crude oil values, so the royalties can be analyzed from both perspectives.

4.3. Royalties as % of Bitumen values.

Color coding the royalties is based on typical international values for royalties. Internationally, royalties of 5% or less are “very low”, royalties of 25% or more are “very high” and royalties between 10% and 17% are “average”.

The following color coding will be used for the maps:

Royalty assessment

IRR < 5%
< 5%
< 10%
< 17%
< 25%
> 25%

IRR	< 5%	- black	
Royalties	< 5%	- gold	- very low
Royalties	< 10%	- blue	- low
Royalties	< 17%	- green	- average
Royalties	< 25%	- brown	- high
Royalties over 25%		- magenta	- very high

The following six tables provide the royalty overview.

Table 4.1. COLD LAKE
Royalties (%/Bitumen barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				4.22%	8.37%	8.86%	10.87%
30	34.09	$4.26	$20.45	5.53%	7.17%	8.50%	9.86%	12.27%	12.55%	13.88%
40	45.45	$5.68	$27.27	9.36%	10.39%	11.39%	12.38%	14.15%	14.39%	15.37%
50	56.82	$7.10	$34.09	11.49%	12.28%	13.10%	13.88%	15.31%	15.47%	16.27%
60	68.18	$8.52	$40.91	12.90%	13.56%	14.22%	14.89%	16.05%	16.20%	16.85%
70	79.55	$9.94	$47.73	13.89%	14.46%	15.03%	15.59%	16.60%	16.71%	17.27%
80	90.91	$11.36	$54.55	14.64%	15.12%	15.62%	16.12%	16.99%	17.10%	17.59%
90	102.27	$12.78	$61.36	15.21%	15.65%	16.09%	16.53%	17.31%	17.40%	17.83%
100	113.64	$14.20	$68.18	15.67%	16.07%	16.47%	16.85%	17.56%	17.64%	18.02%

Table 4.2. SAGD-ATHABASCA
Royalties (%/Bitumen barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						2.53%	6.14%
30	34.09	$4.26	$15.34				4.40%	6.59%	8.35%	10.15%
40	45.45	$5.68	$20.45	3.44%	5.25%	6.80%	8.15%	9.49%	10.82%	12.14%
50	56.82	$7.10	$25.57	6.94%	8.00%	9.07%	10.15%	11.21%	12.27%	13.35%
60	68.18	$8.52	$30.68	8.82%	9.72%	10.61%	11.49%	12.36%	13.26%	14.13%
70	79.55	$9.94	$35.80	10.15%	10.94%	11.68%	12.43%	13.20%	13.94%	14.70%
80	90.91	$11.36	$40.91	11.15%	11.83%	12.48%	13.15%	13.80%	14.46%	15.11%
90	102.27	$12.78	$46.02	11.94%	12.51%	13.11%	13.70%	14.28%	14.87%	15.44%
100	113.64	$14.20	$51.14	12.54%	13.08%	13.62%	14.13%	14.66%	15.18%	15.71%

Table 4.3. SAGD-ATHABASCA+UPGR
Royalties (%/Bitumen barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23							6.14%
30	34.09	$4.26	$15.34				4.40%	6.59%	8.35%	10.15%
40	45.45	$5.68	$20.45	3.44%	5.25%	6.80%	8.15%	9.49%	10.82%	12.14%
50	56.82	$7.10	$25.57	6.94%	8.00%	9.07%	10.15%	11.21%	12.27%	13.35%
60	68.18	$8.52	$30.68	8.82%	9.72%	10.61%	11.49%	12.36%	13.26%	14.13%
70	79.55	$9.94	$35.80	10.15%	10.94%	11.68%	12.43%	13.20%	13.94%	14.70%
80	90.91	$11.36	$40.91	11.15%	11.83%	12.48%	13.15%	13.80%	14.46%	15.11%
90	102.27	$12.78	$46.02	11.94%	12.51%	13.11%	13.70%	14.28%	14.87%	15.44%
100	113.64	$14.20	$51.14	12.54%	13.08%	13.62%	14.13%	14.66%	15.18%	15.71%

Table 4.4. MINE-ATHABASCA
Royalties (%/Bitumen barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						5.45%	9.26%
30	34.09	$4.26	$15.34			4.85%	7.59%	9.98%	12.22%	14.40%
40	45.45	$5.68	$20.45	6.67%	8.58%	10.35%	12.04%	13.67%	15.30%	16.91%
50	56.82	$7.10	$25.57	10.57%	11.91%	13.25%	14.55%	15.85%	17.12%	18.40%
60	68.18	$8.52	$30.68	12.94%	14.03%	15.11%	16.18%	17.27%	18.33%	19.40%
70	79.55	$9.94	$35.80	14.61%	15.52%	16.43%	17.37%	18.27%	19.20%	20.10%
80	90.91	$11.36	$40.91	15.84%	16.63%	17.44%	18.24%	19.04%	19.84%	20.63%
90	102.27	$12.78	$46.02	16.78%	17.50%	18.23%	18.92%	19.64%	20.34%	21.03%
100	113.64	$14.20	$51.14	17.55%	18.20%	18.82%	19.47%	20.10%	20.74%	21.36%

Table 4.5. MINE-ATHABASCA-UPGRADER
Royalties (%/Bitumen barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						5.45%	9.26%
30	34.09	$4.26	$15.34			4.85%	7.59%	9.98%	12.22%	14.40%
40	45.45	$5.68	$20.45	6.67%	8.58%	10.35%	12.04%	13.67%	15.30%	16.91%
50	56.82	$7.10	$25.57	10.57%	11.91%	13.25%	14.55%	15.85%	17.12%	18.40%
60	68.18	$8.52	$30.68	12.94%	14.03%	15.11%	16.18%	17.27%	18.33%	19.40%
70	79.55	$9.94	$35.80	14.61%	15.52%	16.43%	17.37%	18.27%	19.20%	20.10%
80	90.91	$11.36	$40.91	15.84%	16.63%	17.44%	18.24%	19.04%	19.84%	20.63%
90	102.27	$12.78	$46.02	16.78%	17.50%	18.23%	18.92%	19.64%	20.34%	21.03%
100	113.64	$14.20	$51.14	17.55%	18.20%	18.82%	19.47%	20.10%	20.74%	21.36%

Table 4.6. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
Royalties (%/Bitumen barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						12.27%	18.70%
30	34.09	$4.26	$15.34			11.09%	15.65%	19.71%	23.49%	27.13%
40	45.45	$5.68	$20.45	14.02%	17.27%	20.25%	23.11%	25.84%	28.56%	31.22%
50	56.82	$7.10	$25.57	20.57%	22.84%	25.09%	27.21%	29.35%	31.52%	33.60%
60	68.18	$8.52	$30.68	24.53%	26.36%	28.15%	29.92%	31.72%	33.44%	35.17%
70	79.55	$9.94	$35.80	27.30%	28.82%	30.32%	31.85%	33.33%	34.81%	36.31%
80	90.91	$11.36	$40.91	29.33%	30.62%	31.94%	33.25%	34.59%	35.86%	37.17%
90	102.27	$12.78	$46.02	30.86%	32.02%	33.19%	34.38%	35.50%	36.67%	37.80%
100	113.64	$14.20	$51.14	32.08%	33.14%	34.21%	35.22%	36.27%	37.33%	38.33%

Generic system based on bitumen values

In the above maps of the bitumen value is used as the basis for the gross royalty equivalent calculations.

Of course, under the generic regime the royalties are identical with and without upgrading because the royalties are levied on the bitumen values only. In other words there is no royalty on the upgrading component. Therefore tables 4.2 and 4.3 show identical results. This is also the case for Table 4.4 and 4.5.

It can be seen how the gross royalty equivalent rate increases with lower costs and higher prices, this is because the fixed net profit share takes a larger "bite" relative to the gross revenues if profits are higher. The royalties are "very low" to "average" for US $ 30 per barrel WTI or less. For values of $ 50 per barrel WTI and higher the royalties range from "average" to "high". This is what the generic royalty system intends to achieve.

Generic system based on SCO values

Under the current Suncor and Syncrude agreements the royalties are based on SCO values. However, we can calculate a hypothetical gross royalty equivalent based on bitumen values by allocating all the royalty revenues to the bitumen value only.

In this case, the royalty would be "average" to "very high" for US $ 30 per barrel WTI or less. For $ 50 per barrel WTI and more, the royalties would be "very high" except under very high costs.

It seems therefore, that Suncor and Syncrude are currently operating under royalties that would be equivalent to very high royalties based on the gross bitumen value. In other words in the price range of US $ 40 to $ 60 WTI the oil sands projects seem to be able to sustain rather high royalties on bitumen values.

Comparing Tables 4.6 and 4.5 it is very obvious that Alberta is faced with a very high level of royalty reduction, when under the Suncor and Syncrude terms companies opt for a switch to bitumen values from SCO values. Under high price and low cost conditions, such a royalty loss to Alberta does not seem justified by the economics of the projects.

Comparison with international royalties

From a "bitumen value" perspective, the total generic royalties based on bitumen values over the duration of the project are comparable to international royalty levels, which are largely based on gross revenues. On this basis, the royalties are therefore not unusually high or low. It should be noted that this observation relates to the total amount of royalties received over the life of the project. By international standards a royalty of 1% until payout is very low.

4.4. Royalties as % of SCO values.

The color coding is the same as used in sub-chapter 4.3 above.

The following six tables provide the royalty overview.

Table 4.7. COLD LAKE
Royalties (%/SCO barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				2.98%	5.91%	6.25%	7.67%
30	34.09	$4.26	$20.45	3.90%	5.06%	6.00%	6.96%	8.66%	8.86%	9.80%
40	45.45	$5.68	$27.27	6.61%	7.33%	8.04%	8.74%	9.99%	10.15%	10.85%
50	56.82	$7.10	$34.09	8.11%	8.67%	9.25%	9.80%	10.81%	10.92%	11.48%
60	68.18	$8.52	$40.91	9.10%	9.57%	10.04%	10.51%	11.33%	11.44%	11.89%
70	79.55	$9.94	$47.73	9.80%	10.21%	10.61%	11.00%	11.72%	11.79%	12.19%
80	90.91	$11.36	$54.55	10.34%	10.67%	11.03%	11.38%	11.99%	12.07%	12.42%
90	102.27	$12.78	$61.36	10.73%	11.05%	11.36%	11.67%	12.22%	12.28%	12.58%
100	113.64	$14.20	$68.18	11.06%	11.35%	11.63%	11.90%	12.39%	12.45%	12.72%

Table 4.8. SAGD-ATHABASCA
Royalties (%/SCO barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						1.34%	3.25%
30	34.09	$4.26	$15.34				2.33%	3.49%	4.42%	5.37%
40	45.45	$5.68	$20.45	1.82%	2.78%	3.60%	4.31%	5.02%	5.73%	6.43%
50	56.82	$7.10	$25.57	3.67%	4.23%	4.80%	5.37%	5.94%	6.50%	7.07%
60	68.18	$8.52	$30.68	4.67%	5.15%	5.62%	6.08%	6.54%	7.02%	7.48%
70	79.55	$9.94	$35.80	5.37%	5.79%	6.18%	6.58%	6.99%	7.38%	7.78%
80	90.91	$11.36	$40.91	5.90%	6.26%	6.60%	6.96%	7.30%	7.66%	8.00%
90	102.27	$12.78	$46.02	6.32%	6.63%	6.94%	7.25%	7.56%	7.87%	8.17%
100	113.64	$14.20	$51.14	6.64%	6.93%	7.21%	7.48%	7.76%	8.03%	8.31%

Table 4.9. SAGD-ATHABASCA+UPGR
Royalties (%/SCO barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23							3.25%
30	34.09	$4.26	$15.34				2.33%	3.49%	4.42%	5.37%
40	45.45	$5.68	$20.45	1.82%	2.78%	3.60%	4.31%	5.02%	5.73%	6.43%
50	56.82	$7.10	$25.57	3.67%	4.23%	4.80%	5.37%	5.94%	6.50%	7.07%
60	68.18	$8.52	$30.68	4.67%	5.15%	5.62%	6.08%	6.54%	7.02%	7.48%
70	79.55	$9.94	$35.80	5.37%	5.79%	6.18%	6.58%	6.99%	7.38%	7.78%
80	90.91	$11.36	$40.91	5.90%	6.26%	6.60%	6.96%	7.30%	7.66%	8.00%
90	102.27	$12.78	$46.02	6.32%	6.63%	6.94%	7.25%	7.56%	7.87%	8.17%
100	113.64	$14.20	$51.14	6.64%	6.93%	7.21%	7.48%	7.76%	8.03%	8.31%

Table 4.10. MINE-ATHABASCA
Royalties (%/SCO barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						2.89%	4.90%
30	34.09	$4.26	$15.34			2.57%	4.02%	5.28%	6.47%	7.62%
40	45.45	$5.68	$20.45	3.53%	4.54%	5.48%	6.37%	7.24%	8.10%	8.95%
50	56.82	$7.10	$25.57	5.60%	6.31%	7.01%	7.70%	8.39%	9.07%	9.74%
60	68.18	$8.52	$30.68	6.85%	7.43%	8.00%	8.56%	9.14%	9.70%	10.27%
70	79.55	$9.94	$35.80	7.74%	8.22%	8.70%	9.19%	9.67%	10.16%	10.64%
80	90.91	$11.36	$40.91	8.38%	8.80%	9.23%	9.65%	10.08%	10.51%	10.92%
90	102.27	$12.78	$46.02	8.88%	9.27%	9.65%	10.02%	10.40%	10.77%	11.13%
100	113.64	$14.20	$51.14	9.29%	9.64%	9.97%	10.31%	10.64%	10.98%	11.31%

Table 4.11. MINE-ATHABASCA-UPGRADER
Royalties (%/SCO barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						2.89%	4.90%
30	34.09	$4.26	$15.34			2.57%	4.02%	5.28%	6.47%	7.62%
40	45.45	$5.68	$20.45	3.53%	4.54%	5.48%	6.37%	7.24%	8.10%	8.95%
50	56.82	$7.10	$25.57	5.60%	6.31%	7.01%	7.70%	8.39%	9.07%	9.74%
60	68.18	$8.52	$30.68	6.85%	7.43%	8.00%	8.56%	9.14%	9.70%	10.27%
70	79.55	$9.94	$35.80	7.74%	8.22%	8.70%	9.19%	9.67%	10.16%	10.64%
80	90.91	$11.36	$40.91	8.38%	8.80%	9.23%	9.65%	10.08%	10.51%	10.92%
90	102.27	$12.78	$46.02	8.88%	9.27%	9.65%	10.02%	10.40%	10.77%	11.13%
100	113.64	$14.20	$51.14	9.29%	9.64%	9.97%	10.31%	10.64%	10.98%	11.31%

Table 4.12. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
Royalties (%/SCO barrel)

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						6.50%	9.90%
30	34.09	$4.26	$15.34			5.87%	8.28%	10.44%	12.44%	14.36%
40	45.45	$5.68	$20.45	7.42%	9.15%	10.72%	12.23%	13.68%	15.12%	16.53%
50	56.82	$7.10	$25.57	10.89%	12.09%	13.28%	14.41%	15.54%	16.69%	17.79%
60	68.18	$8.52	$30.68	12.99%	13.95%	14.90%	15.84%	16.79%	17.71%	18.62%
70	79.55	$9.94	$35.80	14.45%	15.26%	16.05%	16.86%	17.65%	18.43%	19.23%
80	90.91	$11.36	$40.91	15.53%	16.21%	16.91%	17.60%	18.31%	18.98%	19.68%
90	102.27	$12.78	$46.02	16.34%	16.95%	17.57%	18.20%	18.80%	19.42%	20.01%
100	113.64	$14.20	$51.14	16.98%	17.54%	18.11%	18.65%	19.20%	19.76%	20.29%

Generic system based on bitumen values

The above tables show that for values of US $ 30 or less, the generic royalty system generates "very low" or "low" royalties. This seems justified under the circumstances, because under these price levels and under current cost conditions oil sands projects are not attractive or only modestly attractive from an investor point of view.

In order words the royalties seem adequate under low prices. The royalty system assists in sharing the downside price risk between government and investors. It makes it possible for investors to continue operations under low prices and even continue to invest in low cost expansions or ventures.

However, for the price range of US $ 50 or higher, the royalties are:

- average for Cold Lake SAGD development
- low for Athabasca SAGD oil sands developments, and
- low for mining projects, except for low cost cases where the royalties become "average" under high prices.

Generic system based on SCO values

Based on current Suncor and Syncrude terms, the royalties are average for the price range of US $ 40 to $ 60 per barrel WTI.

Effect of high costs on royalties

At about US $ 50 per barrel WTI, the royalties on Cost-7 projects are only half the royalties on Cost-1 projects.

In an environment where Alberta is already faced with a very high level of investment and cost escalation, the issue can be raised whether Alberta should continue to stimulate the development of very high cost production operations on which only low royalties are being collected.

Providing disincentives through the royalty regime for projects with cost level Cost-6 or Cost-7 could result in a moderation of the future level of production activity without loosing important royalty revenues, since the royalties are low anyway for such high cost ventures, while continued high escalation may be threatening to upgrading projects with higher value added opportunities.

Comparison with international royalties

From an international perspective, and based on synthetic crude values, the royalties are unattractive from a government perspective for prices in excess of US $ 50 WTI. The government could levy higher royalties under prices of US $ 50 or higher without creating unacceptable economic conditions for investors. This would be true in particular for projects in the cost range of Cost-3 or less.

4.5. Undiscounted Government Take

Color coding the undiscounted government take is based on typical international values for government take. Internationally, government take of 40% or less is "very low", a government take of 85% or more is "very high" and a government take between 55% and 65% is average.

It should be noted that "low" or "high" government takes are relative to the international average. A "low" government take does not necessarily mean that the government take is inappropriate or disadvantageous for the province or country. The level of government take is largely determined by market forces. One finds very high government takes in countries that have abundant resources at very low costs, such as is typically the case in the Middle East or North Africa. Very low or low government takes occur in countries that have only modest resource potential or that experience high cost conditions such as Southern Europe or inland basins in Africa. In both cases the very high or very low government take is appropriate for the circumstances and is competitive from an international point of view.

In other words a "low" government take does not necessarily mean an "uncompetitive" government take. Nor does it mean that the country or province does not receive its fair share. In future reports the competitiveness of the Alberta system will be evaluated in more detail. In this report the government take in absolute terms will be reviewed.

The following color coding will be used for the maps:

Gov Take assessment

IRR < 5%	
< 40%	
< 55%	
< 65%	
< 85%	
> 85%	

IRR	< 5%	- black	
Government Take	< 40%	- gold	- very low
Government Take	< 55%	- blue	- low
Government Take	< 65%	- green	- average
Government Take	< 85%	- brown	- high
Government Take over 85%		- magenta	- very high

Table 4.13. COLD LAKE
Undiscounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				45.74%	47.63%	47.71%	47.69%
30	34.09	$4.26	$20.45	46.86%	47.69%	47.65%	47.67%	47.69%	47.67%	47.64%
40	45.45	$5.68	$27.27	47.68%	47.70%	47.69%	47.66%	47.63%	47.64%	47.60%
50	56.82	$7.10	$34.09	47.69%	47.66%	47.67%	47.64%	47.64%	47.60%	47.60%
60	68.18	$8.52	$40.91	47.67%	47.66%	47.64%	47.64%	47.60%	47.60%	47.57%
70	79.55	$9.94	$47.73	47.64%	47.64%	47.63%	47.60%	47.60%	47.57%	47.56%
80	90.91	$11.36	$54.55	47.64%	47.61%	47.60%	47.60%	47.57%	47.57%	47.56%
90	102.27	$12.78	$61.36	47.61%	47.60%	47.60%	47.59%	47.57%	47.56%	47.54%
100	113.64	$14.20	$68.18	47.60%	47.60%	47.60%	47.57%	47.56%	47.56%	47.54%

Table 4.14. SAGD-ATHABASCA
Undiscounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						43.73%	47.87%
30	34.09	$4.26	$15.34				46.53%	47.82%	47.73%	47.71%
40	45.45	$5.68	$20.45	45.23%	47.18%	47.78%	47.76%	47.74%	47.71%	47.66%
50	56.82	$7.10	$25.57	47.77%	47.72%	47.70%	47.70%	47.67%	47.65%	47.65%
60	68.18	$8.52	$30.68	47.74%	47.74%	47.71%	47.68%	47.65%	47.65%	47.61%
70	79.55	$9.94	$35.80	47.69%	47.72%	47.68%	47.64%	47.65%	47.61%	47.60%
80	90.91	$11.36	$40.91	47.67%	47.68%	47.64%	47.64%	47.61%	47.61%	47.58%
90	102.27	$12.78	$46.02	47.68%	47.64%	47.64%	47.63%	47.61%	47.60%	47.57%
100	113.64	$14.20	$51.14	47.64%	47.64%	47.64%	47.61%	47.60%	47.58%	47.57%

Table 4.15. SAGD-ATHABASCA+UPGR
Undiscounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23							38.36%
30	34.09	$4.26	$15.34				37.09%	38.06%	38.32%	38.53%
40	45.45	$5.68	$20.45	36.20%	37.35%	37.91%	38.15%	38.33%	38.46%	38.56%
50	56.82	$7.10	$25.57	37.84%	38.02%	38.18%	38.31%	38.42%	38.50%	38.59%
60	68.18	$8.52	$30.68	38.10%	38.22%	38.32%	38.40%	38.47%	38.54%	38.59%
70	79.55	$9.94	$35.80	38.22%	38.33%	38.38%	38.44%	38.50%	38.55%	38.60%
80	90.91	$11.36	$40.91	38.30%	38.38%	38.42%	38.48%	38.52%	38.56%	38.59%
90	102.27	$12.78	$46.02	38.37%	38.41%	38.46%	38.50%	38.53%	38.57%	38.60%
100	113.64	$14.20	$51.14	38.39%	38.44%	38.49%	38.51%	38.55%	38.57%	38.60%

Table 4.16. MINE-ATHABASCA
Undiscounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						45.24%	47.11%
30	34.09	$4.26	$15.34			44.43%	46.51%	47.16%	47.39%	47.48%
40	45.45	$5.68	$20.45	45.93%	46.82%	47.20%	47.39%	47.45%	47.51%	47.52%
50	56.82	$7.10	$25.57	47.23%	47.35%	47.45%	47.49%	47.52%	47.52%	47.53%
60	68.18	$8.52	$30.68	47.41%	47.46%	47.48%	47.49%	47.52%	47.52%	47.54%
70	79.55	$9.94	$35.80	47.49%	47.50%	47.50%	47.52%	47.52%	47.53%	47.53%
80	90.91	$11.36	$40.91	47.51%	47.50%	47.53%	47.52%	47.53%	47.54%	47.53%
90	102.27	$12.78	$46.02	47.51%	47.53%	47.54%	47.53%	47.54%	47.53%	47.52%
100	113.64	$14.20	$51.14	47.53%	47.54%	47.53%	47.54%	47.53%	47.53%	47.52%

Table 4.17. MINE-ATHABASCA-UPGRADER
Undiscounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						36.97%	38.49%
30	34.09	$4.26	$15.34			36.60%	38.01%	38.68%	39.05%	39.30%
40	45.45	$5.68	$20.45	37.63%	38.35%	38.77%	39.06%	39.25%	39.40%	39.52%
50	56.82	$7.10	$25.57	38.83%	39.05%	39.22%	39.35%	39.46%	39.55%	39.62%
60	68.18	$8.52	$30.68	39.19%	39.31%	39.40%	39.48%	39.57%	39.62%	39.69%
70	79.55	$9.94	$35.80	39.38%	39.45%	39.51%	39.58%	39.63%	39.68%	39.72%
80	90.91	$11.36	$40.91	39.48%	39.53%	39.59%	39.63%	39.68%	39.72%	39.75%
90	102.27	$12.78	$46.02	39.54%	39.59%	39.64%	39.67%	39.71%	39.74%	39.76%
100	113.64	$14.20	$51.14	39.60%	39.64%	39.67%	39.70%	39.73%	39.76%	39.78%

Table 4.18. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
Undiscounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						45.02%	46.81%
30	34.09	$4.26	$15.34			44.31%	46.07%	46.85%	47.20%	47.38%
40	45.45	$5.68	$20.45	45.51%	46.42%	46.89%	47.17%	47.32%	47.43%	47.49%
50	56.82	$7.10	$25.57	46.91%	47.12%	47.29%	47.35%	47.42%	47.49%	47.51%
60	68.18	$8.52	$30.68	47.23%	47.33%	47.39%	47.43%	47.49%	47.50%	47.51%
70	79.55	$9.94	$35.80	47.38%	47.42%	47.44%	47.48%	47.49%	47.50%	47.52%
80	90.91	$11.36	$40.91	47.44%	47.45%	47.47%	47.49%	47.52%	47.51%	47.53%
90	102.27	$12.78	$46.02	47.46%	47.47%	47.49%	47.51%	47.51%	47.52%	47.52%
100	113.64	$14.20	$51.14	47.47%	47.48%	47.51%	47.50%	47.52%	47.53%	47.52%

Generic system based on bitumen values

The evaluation of the above tables makes it clear that measured against the bitumen values, the government take of Alberta is “low” in the 46% to 48% range and measured against SCO prices the government take is “very low” in the 36% to 39% range for the generic royalty system.

An interesting feature of the Alberta system is that the government take is essentially “flat”. This means the government take is approximately the same for every cost and price combination. Only under very unfavorable combinations does the government take dip somewhat.

The reason that the government take is the same for every cost-price combination is that:

- an important component of the government take is the corporate income tax which is “flat” for every price and cost level, and
- the main feature of the royalties is also based on a fixed share of net income. Also royalties are now deductible for corporate income tax.

Generic system based on SCO prices

It can also be seen from tables 4.17 and 4.18 that the switch from basing royalties on the SCO price to bitumen prices under the Suncor/Syncrude arrangements will result in a drop of about 8% in overall government take. However, that drop is only experienced by Alberta, the Federal share actually goes up, since royalties are now deductible for tax purposes.

Comparison with international government takes

It should be noted that some countries have “regressive” systems whereby the government take actually goes down under higher prices and lower costs, while other countries have “progressive” systems whereby the government take goes up with higher prices and lower costs. Many important oil exporting countries have progressive systems.

In general, it appears that there would be a considerable possibility for introducing a progressive fiscal system in Alberta. Under high prices and low costs, the oil sands developments are highly attractive to investors, yet Alberta only receives a very low government take under the generic royalty system measured on SCO prices as Table 4.11 illustrates.

4.6. 5% Discounted Government Take

In general around the world the 5% discounted government take is somewhat higher than the undiscounted government take. The reason is that many systems have royalties which are being paid early in the cash flow, usually as soon as production starts. At the same time many corporate income tax systems provide for depreciation of the assets over time and therefore tax is payable well before payout time is being reached. Because of these early payments, the government revenues are more attractive on a discounted basis. The government receives a higher percentage of the 5% discounted divisible income or in other words a higher government take if the time value of money is taken into account.

This means that the system is somewhat "front end loaded" in terms of payments to government.

For analytical purposes, however, we will use the same color coded scale, which is as displayed below.

5% Gov Take assessment

IRR < 5%
< 40%
< 55%
< 65%
< 85%
> 85%

IRR	< 5%	- black	
Government Take	< 40%	- gold	- very low
Government Take	< 55%	- blue	- low
Government Take	< 65%	- green	- average
Government Take	< 85%	- brown	- high
Government Take over 85%		- magenta	- very high

The 5% discounted government take maps are provided below.

Table 4.19 COLD LAKE
5% Discounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$13.64				88.97%	55.53%	53.06%	50.51%
30	34.09	$4.26	$20.45	68.56%	58.52%	53.93%	51.71%	50.09%	49.49%	48.84%
40	45.45	$5.68	$27.27	52.55%	51.27%	50.34%	49.63%	48.98%	48.70%	48.35%
50	56.82	$7.10	$34.09	50.31%	49.71%	49.31%	48.91%	48.58%	48.34%	48.14%
60	68.18	$8.52	$40.91	49.42%	49.09%	48.80%	48.58%	48.31%	48.17%	47.98%
70	79.55	$9.94	$47.73	48.94%	48.73%	48.53%	48.34%	48.17%	48.02%	47.91%
80	90.91	$11.36	$54.55	48.68%	48.47%	48.33%	48.21%	48.04%	47.95%	47.85%
90	102.27	$12.78	$61.36	48.45%	48.33%	48.22%	48.10%	47.97%	47.89%	47.79%
100	113.64	$14.20	$68.18	48.33%	48.23%	48.13%	48.01%	47.92%	47.85%	47.76%

Table 4.20. SAGD-ATHABASCA
5% Discounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						338.88%	60.13%
30	34.09	$4.26	$15.34				78.34%	58.27%	52.65%	50.39%
40	45.45	$5.68	$20.45	114.74%	67.53%	57.49%	53.32%	51.22%	49.95%	49.09%
50	56.82	$7.10	$25.57	57.10%	53.68%	51.74%	50.54%	49.68%	49.04%	48.62%
60	68.18	$8.52	$30.68	52.28%	51.11%	50.23%	49.55%	49.03%	48.67%	48.33%
70	79.55	$9.94	$35.80	50.61%	50.03%	49.47%	49.02%	48.71%	48.40%	48.18%
80	90.91	$11.36	$40.91	49.79%	49.41%	49.01%	48.74%	48.46%	48.26%	48.04%
90	102.27	$12.78	$46.02	49.37%	49.01%	48.77%	48.53%	48.32%	48.16%	47.97%
100	113.64	$14.20	$51.14	49.00%	48.79%	48.59%	48.37%	48.22%	48.04%	47.92%

Table 4.21. SAGD-ATHABASCA+UPGR
5% Discounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23							54.12%
30	34.09	$4.26	$15.34				61.76%	48.27%	43.99%	42.08%
40	45.45	$5.68	$20.45	69.97%	52.01%	46.33%	43.64%	42.15%	41.20%	40.54%
50	56.82	$7.10	$25.57	45.38%	43.39%	42.16%	41.35%	40.74%	40.29%	39.96%
60	68.18	$8.52	$30.68	42.23%	41.50%	40.94%	40.49%	40.13%	39.87%	39.63%
70	79.55	$9.94	$35.80	41.05%	40.68%	40.32%	40.02%	39.81%	39.60%	39.44%
80	90.91	$11.36	$40.91	40.45%	40.20%	39.95%	39.76%	39.57%	39.43%	39.29%
90	102.27	$12.78	$46.02	40.11%	39.89%	39.73%	39.57%	39.43%	39.32%	39.20%
100	113.64	$14.20	$51.14	39.84%	39.70%	39.57%	39.43%	39.33%	39.21%	39.13%

Table 4.22. MINE-ATHABASCA
5% Discounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						68.92%	52.79%
30	34.09	$4.26	$15.34			79.80%	57.20%	52.10%	50.05%	48.98%
40	45.45	$5.68	$20.45	61.43%	54.74%	51.87%	50.34%	49.38%	48.78%	48.35%
50	56.82	$7.10	$25.57	51.73%	50.48%	49.69%	49.09%	48.68%	48.34%	48.08%
60	68.18	$8.52	$30.68	49.86%	49.32%	48.89%	48.55%	48.33%	48.11%	47.96%
70	79.55	$9.94	$35.80	49.14%	48.80%	48.51%	48.33%	48.13%	48.00%	47.85%
80	90.91	$11.36	$40.91	48.73%	48.48%	48.32%	48.14%	48.02%	47.91%	47.80%
90	102.27	$12.78	$46.02	48.46%	48.32%	48.19%	48.05%	47.95%	47.84%	47.74%
100	113.64	$14.20	$51.14	48.32%	48.21%	48.07%	47.98%	47.87%	47.80%	47.71%

Table 4.23. MINE-ATHABASCA-UPGRADER
5% Discounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						50.32%	43.01%
30	34.09	$4.26	$15.34			55.40%	45.78%	42.88%	41.58%	40.86%
40	45.45	$5.68	$20.45	48.25%	44.60%	42.84%	41.85%	41.20%	40.78%	40.47%
50	56.82	$7.10	$25.57	42.83%	42.00%	41.45%	41.03%	40.73%	40.48%	40.29%
60	68.18	$8.52	$30.68	41.61%	41.22%	40.92%	40.67%	40.50%	40.33%	40.21%
70	79.55	$9.94	$35.80	41.11%	40.86%	40.65%	40.51%	40.35%	40.25%	40.14%
80	90.91	$11.36	$40.91	40.82%	40.64%	40.51%	40.38%	40.28%	40.19%	40.10%
90	102.27	$12.78	$46.02	40.63%	40.52%	40.42%	40.31%	40.23%	40.14%	40.06%
100	113.64	$14.20	$51.14	40.52%	40.43%	40.33%	40.25%	40.17%	40.11%	40.04%

Table 4.24. MINE-ATHABASCA-UPGRADER (current Suncor/Syncrude terms)
5% Discounted Government Take

WTI US $	WTI Can $	Gas Price Can $	Bit Price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$2.84	$10.23						65.10%	53.07%
30	34.09	$4.26	$15.34			72.63%	57.16%	52.52%	50.38%	49.23%
40	45.45	$5.68	$20.45	60.92%	55.16%	52.32%	50.72%	49.68%	49.01%	48.53%
50	56.82	$7.10	$25.57	52.21%	50.88%	50.02%	49.31%	48.83%	48.51%	48.20%
60	68.18	$8.52	$30.68	50.22%	49.62%	49.15%	48.76%	48.50%	48.24%	48.02%
70	79.55	$9.94	$35.80	49.41%	49.04%	48.71%	48.48%	48.26%	48.06%	47.93%
80	90.91	$11.36	$40.91	48.96%	48.68%	48.46%	48.28%	48.14%	47.98%	47.87%
90	102.27	$12.78	$46.02	48.66%	48.45%	48.29%	48.17%	48.01%	47.92%	47.80%
100	113.64	$14.20	$51.14	48.44%	48.30%	48.19%	48.04%	47.95%	47.87%	47.77%

Comparison of undiscounted and discounted results

When comparing the tables 4.13 through 4.18 of the undiscounted government take, with tables 4.19 through 4.24 for the 5% discounted government take, it can be seen how for every price-cost combination the discounted government take is higher than the undiscounted government take. This is due to the modest front end loading of the fiscal system overall. This matter will be evaluated in somewhat more detail below.

It can also be observed how the difference between the 5% discounted government take and the undiscounted government take increases with lower prices and higher costs. The higher 5% discounted government take at low prices may be somewhat counter-productive since it increases the downside price risk.

This matter will be analyzed in more detail in section 4.7 of this report.

Generic system based on SCO values

The switch to bitumen pricing from SCO pricing for Suncor/Syncrude terms will result in a considerable government take loss on a discounted basis.

Comparison with international government takes

In general, the 5% discounted government take based both on bitumen or SCO prices is now "low" in both cases. A considerable difference exist between the government take based on bitumen and SCO prices.

4.7. Royalty and tax feature analysis

An interesting feature for a possible royalty review is to provide an analysis of the importance of the individual features of the generic royalty regime. A set of examples will be provided based on the generic regime as currently applicable to Suncor and Syncrude.

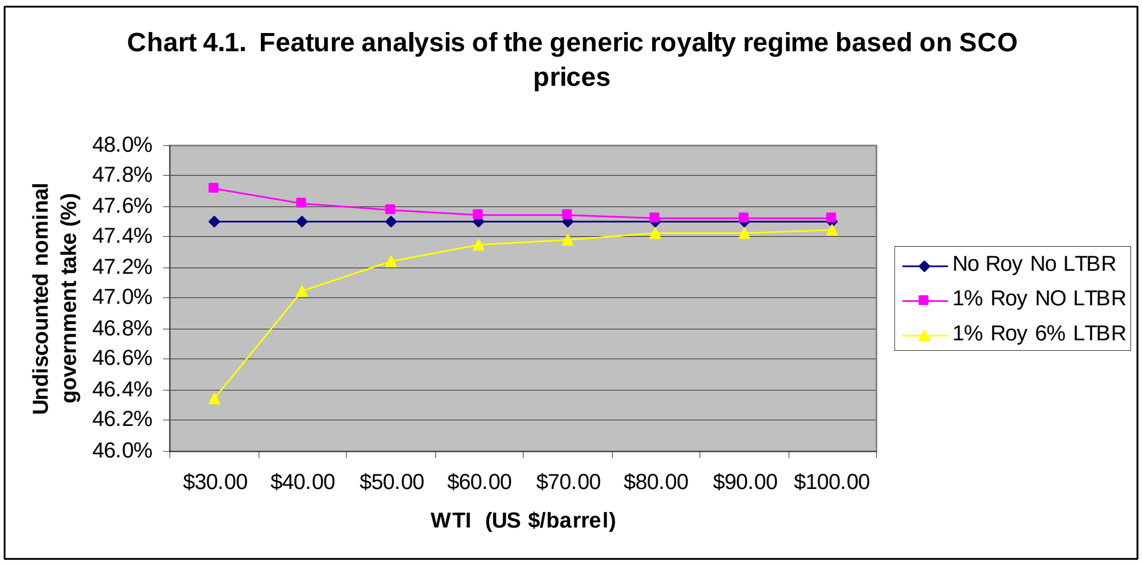
Analysis of royalty features

Firstly, the importance of the royalty features for the overall government take can be reviewed.

If in the generic royalty regime the base royalty would be set at 0% and the long term bond rate would be eliminated from the payout calculation, the government take on a nominal basis would be by definition 47.5%. This is because the royalty would now entirely be based on nominal cumulative cash flow. The royalty would be 25% of this cash flow and this royalty is tax deductible. Subsequently, 30% tax would be levied on the remaining 75%. In other words the government take in nominal terms would be:

$$47.5\% = 25\% + 0.75 * 30\%$$

The Chart 4.1 illustrates how the 1% base royalty and the introduction of the long term bond rate change the undiscounted nominal government take



The 1% base royalty increases the overall government take. As can be expected the overall increase is very modest since the base royalty rate is modest. At low oil prices the increase is strongest. At a price of US $ 30 WTI the government take would increase from 47.5% to 47.7%.

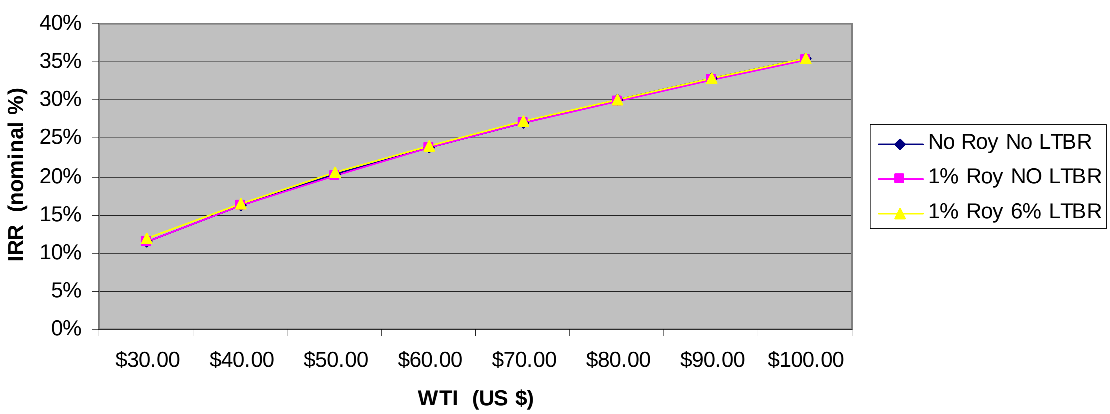
The application of the long term bond rate to the payout calculation (here assumed to be 6% nominal), lowers the undiscounted nominal government take. Again the effect is strongest at low prices. At US $ 30 WTI the government take would now be 46.4%.

The effect of the long term bond rate therefore offsets the effect of the 1% base royalty.

In general, it should be noted that the government range of 46.4% to 47.7% is a very narrow range from an international perspective. Therefore, the impact of these royalty features on investment behavior will be very modest. Chart 4.2. illustrates the nominal IRR rates of the three options.

As can be seen from the graph, the IRR variation is very minor. At a price of US $ 30 WTI, the nominal IRR drops from 11.55% to 11.46% with the introduction of the basic royalty of 1% and increases to 11.79% with the introduction of the long term bond rate of 6%.

Chart 4.2. Feature analysis of generic royalty regime based on SCO prices



Analysis of front end loading and back end loading

The concept of “front end loading” means that the government takes a higher proportion of its government take early in the cash flow, while “back end loading” means that the government takes a higher proportion of the government take late in the cash flow. Front end loading causes the 5% discounted real government take to be higher than the nominal undiscounted government take.

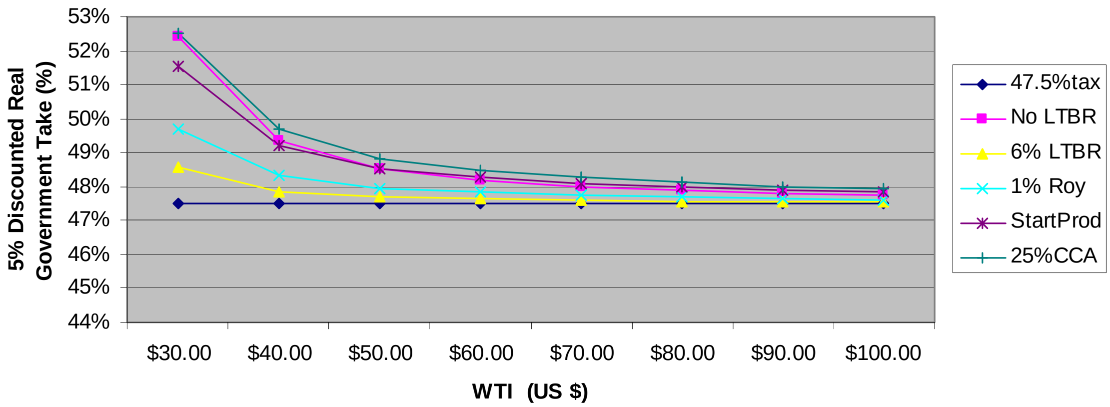
The nature of front end versus back end loading of the total Alberta fiscal system merits some further analysis. This will be analyzed by evaluating the government take in nominal and 5% discounted real terms.

Hypothetically, it is possible to generate a system that both on an undiscounted and discounted generates a government take of 47.5%. This can be achieved if there would be simply a 17.5% surcharge on Alberta corporate income tax rather than a royalty. In this hypothetical case all capital expenditures would have to be expensed for tax purposes from the moment costs are incurred and the tax payer would have to have sufficient taxable income to absorb all deductions. In this system the government take is 47.5% discounted and undiscounted.

Starting from this hypothetical system small steps can be analyzed that lead to the currently applicable system.

The following chart illustrates the feature analysis of the individual components.

Chart 4.3. Feature analysis of the various components of the Alberta fiscal system



The first adjustment would be to replace the 17.5% Alberta tax surcharge with the 25% profit sharing royalty, but without long term bond rate for payout and without base royalty of 1% ("No LTBR" in the graph).

This adjustment increases the 5% discount rate significantly. The reason is that the 25% profit sharing royalty is a ring fenced feature. Rather than taking the tax deductions right away when incurring costs, the costs are being recovered as part of the royalty calculation and as a result the payment of royalty is deferred, until payout is reached. A ring fenced fiscal feature is less attractive than full tax consolidation on the basis of a fully expensed system. As a result the "No LTBR" line shows a 5% discounted government take of 52.4% at a WTI price of US $ 30 per barrel, rather than the base of 47.5%.

The second adjustment is to apply the 6% long term bond rate for payout calculation purposes ("6% LTBR" in the graph). The purpose of this feature is to create back end loading and permit investors the recovery of a level of profitability prior to applying the 25% profit sharing royalty. The graph illustrates how indeed the 6% LTBR application has a back end loading effect. The 5% discounted government take now reduces again from 52.4% to 48.6%. Interestingly, the 6% LTBR in these economic examples does not fully compensate for the fact that the royalty feature is ring fenced, but the results are rather close.

The third adjustment is to apply the 1% base royalty. By definition this is a front end loaded feature and as a result the 5% discounted government take is somewhat higher at 49.7% compared to 48.6% at US $ 30 per barrel WTI ("1% royalty" in the graph).

The fourth adjustment is to start the expensing of the CCA and ACCA at the start of production rather than when costs are incurred. This is feature that causes front end loading since the investor can no longer benefit from the write offs when investing in these assets ("StartProd" in the graph). As can be seen, the fact that the corporate income tax system requires the depreciation of these assets at the start of production increases the 5% discounted government take considerably, from 49.7% to 51.6%.

The fifth and final adjustment is to include the 30% declining balance depreciation for the CDE's and 25% declining balance depreciation for the CCA's ("25% CCA" in the graph) instead of direct write offs. This increases the 5% discounted government take further from 51.6% to 52.5%.

In summary the overall system has only one feature that is causing back end loading, which is the application of the 6% LTBR. All other features cause a degree of front end loading. These features are:

- The ring fenced nature of the 25% profit sharing royalty
- The 1% base royalty
- The fact that CCA and ACCA are delayed by 24 months or start when only after when the assets come into productive use, and
- The yearly depreciation based on the declining balance method of CDE's and CCA's, rather than a 100% expensing of these capital items.

The effect of front end loading is stronger when oil prices are low than when they are high. At high oil prices, the effect is relatively minor.

5. ROYALTY AND GOVERNMENT TAKE ISSUES

The economic-fiscal analysis raises a number of issues for possible further review. Following is a brief summary of these initial issues:

1. In general is seems that based on the IRR, PFR10 (profitability ratio discounted at 10%) or NPV10/BOE (net present value discounted at 10% divided by the number of barrels equivalent) the Cold Lake developments are more profitable than Athabasca oil sands developments regardless of whether mining or SAGD is being used or whether the bitumen is upgraded or not. This is because the Cold Lake bitumen prices are higher than the Athabasca bitumen prices.

2. In general terms, Cold Lake developments seem clearly unattractive under a WTI price of US $ 20 per barrel and Athabasca oil sands developments seem unattractive under a WTI price of US $ 30 per barrel, except for very low cost operations.

3. The attractiveness depends very much on the level of costs. Cost per barrel and capital investments required to achieve peak production vary over a wide range. Expensive projects could be twice as expensive per barrel as low cost projects.

4. At WTI prices of US $ 30 per barrel for Cold Lake and US $ 40 per barrel for Athabasca oil sands, developments seem acceptable, attractive or very attractive for investors based on IRR, PFR10 or NPV10/BOE for projects of average or low cost (Cost level 5 or lower).

5. The oil sands projects are large in terms of cumulative production by international standards. They offer very attractive opportunities for large scale resource access without exploratory risk in a way that is almost unique in the world.

6. Because of the large size of oil sands projects they provide for very attractive total net present values discounted at 10% (NPV10) for prices of US $ 40 and higher for Cold Lake developments and US $ 50 and higher for oil sands developments for average or low costs. In fact, there are few opportunities in the world providing such high levels of NPV10 at such price levels. The projects are therefore unusual value generators for the investors.

7. In oil sands developments about half the NPV10 is generated by the upgrading process. Therefore, upgrading enhances the value considerably and is inherent in the overall process of value creation of synthetic crude oil.

8. Royalties are very sensitive to prices and costs. Measured on the bases of the bitumen values, royalties are comparable to international royalty rates. Royalties are “low” when projects economics are unacceptable and “high” when project economics are favorable.

9. However, royalties measured on the basis of the gross revenues from synthetic crude oil are low or very low by international standards. Only under very high prices and low costs royalties become average in some cases, in particular for Cold Lake projects.

10. Royalties are very low under high cost conditions and current price expectations. This raises the issue whether it is in the interest of Alberta to continue to stimulate through the fiscal system such very high cost production ventures. Providing a fiscal disincentive for very high cost oil sands production ventures may assist in avoiding excessive cost escalation in the Alberta economy and thereby facilitating an environment for upgrading projects with higher value added opportunities.

11. The overall undiscounted government take is low when calculated on the basis of bitumen values and very low when calculated on the basis of synthetic crude oil values. The 5% discounted government take is low in both cases.

12. The government take is “flat” or “neutral”. This means that the government take is more or less the same regardless of costs, prices or profitability. This is largely due to the fact that both royalties and corporate income tax are based on net income.

13. The low or very low government take may well be adequate under conditions of low prices and high costs. However, it seems that there is considerable space for creating a progressive government take. This is a fiscal system whereby the government take goes up through higher royalties or special taxes under conditions of higher prices and lower costs.

14. Under the Suncor/Syncrude terms companies will have the option to switch from an SCO based pricing system to a bitumen based pricing system. This switch results in very considerable reduction of royalty revenues for Alberta.