

Submission

To

Government of Alberta

Oil Sands Royalty Review Panel

By

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Alberta Oil Sands Royalties

Are Present Royalties (AR185/97) Fair?

In order to answer that question, the review panel will have to determine the current and forecast levels of profitability across the highly variable spectrum of oil sands operations.

Provincial royalties cannot take all of the net revenue available from oil sands projects without destroying their long term viability and discouraging investment in new projects.

In this regard, the review panel will have to agree on a reasonable set of forecast assumptions. There seems to be some acceptance of the following set of assumptions for the short term:

	<u>Average 2007-2010</u>	<u>Range 2007-2010</u>
W.T.I. Oil Price (US\$/Bbl)	\$60.00	\$40.00-80.00
Natural Gas (AECO) (C\$/Bbl)	\$ 7.50	\$ 6.00 - 9.00
Exchange Rate (US\$/C\$)	\$ 0.87	\$ 0.82 - 0.92
Canadian LTBR	5%	4%-6%
Cost of Upgrading (Crude Bitumen to Synthetic Crude)		
\$C per Bbl	\$19.00	\$ 8.00 - 30.00

Any royalty regime must be flexible enough to provide the Province, as owner of the resource, with a fair share of net revenues under "average" conditions. It may also be desirable to accommodate the industry with some relief in periods of low prices, provided such accommodation is balanced with higher royalties in times of above average oil prices. A relief balanced with reward royalty system is worth considering because it assists the industry to maintain operations during low prices and it also diverts an increased share of revenues away from federal income taxes in favor of the Province, the owner of the resource.

Based on the average assumptions listed on page one, a typical oil sands mine in Alberta would look something like this:

<u>Item</u>	<u>\$Can/Bbl</u>
Revenue W.T.I. Oil Price \$60.00 U.S./Bbl at 0.87 U.S./C\$	69.00
Less Costs	
Operating costs including upgrading and after tax return on capital of 10%	44.00
Net Revenue per Bbl	25.00
Present Alberta Pre-Payout Royalty at 1% Gross Revenue	0.69
Present Alberta Royalty after Payout at 25% of Net Revenue	6.25
Recommended Royalty \$C8.62/Bbl plus P.R. Tax (16.38x25.0%)=\$C4.09	12.71

The Alberta pre-payout royalty of 1% clearly provides the Province with an inadequate share of net revenue. It was established at a time when prices were lower than operating costs to provide an incentive to obtain oil sands development. It may still be an appropriate proxy for "royalty free" oil at prices below \$C44.00 (W.T.I. Below \$U.S. 38.28). The question is whether it is appropriate to subsidize oil production to this extent and for the length of time required (until total payout) in the present royalty regulations? Assuming the subsidy was necessary, why not reduce it (charge progressively higher royalties) when prices recover, rather than locking in at nominal rates for years until project payout? Furthermore, why allow continuous expensive project expansions to extend the low 1% royalties indefinitely into the future? The net effect of the failure to place either financial, time or production limits on the 1% rate is to place existing producers at a huge competitive advantage over new entrants. Existing producers can and are using huge profits which are partially created by nominal royalties to fund continuous expansion, thereby monopolizing skilled labor and suppliers to make it very difficult for new entrants. A side effect of this has been the creation of inflation throughout the entire Alberta economy, at the expense of everyone, including residents who are not even employed in the oil and gas industry.

The post payout royalty at 25% of net revenue also needs to be examined. It must be remembered that this royalty is charged only after the developer has recovered his entire investment, including a return allowance at the Long Term Bond Rate. No other jurisdiction in the world defers so much of its resource royalties for so long, or assumes so much of the project risk. Because of this huge and lengthy royalty holiday the post payout royalty might be expected to be comparatively high. A major question is high compared to what?

It is proposed that the appropriate comparable is off-shore oil fields. Off-shore oil exploration and development is high risk, high cost for typically smaller volumes than are found in the oil sands. Huge capital outlays are required for drilling and production platforms and costly under-sea pipelines.

These off-shore oil fields are appropriate comparables to the oil sands because increasingly, additional oil reserves are being developed off-shore. To a larger degree, off-shore sources are the supply alternative to the oil sands.

The Royalty Review Panel should closely examine oil production revenues, costs and royalty and revenue taxation systems in Newfoundland, Norway, United Kingdom, and the United States (Gulf of Mexico and Alaska). Perhaps the best comparable is the United States Gulf of Mexico where deep water oil fields are charged a 12.5% ad valorem royalty after the first 87.5 million barrels of royalty free production. Royalties are in addition to a 35% Federal Income Tax. Even with this higher royalty regime, high risk environment, and high exploration and development costs, lease sales attract significant bonus bids. It would therefore seem obvious that Alberta oil sands royalties should, on average, exceed 12.5% of the W.T.I. Oil Price, with a considerable increase above that share after payout. These royalties would, of course, be charged in addition to

normal Provincial and Federal income taxes. The Provincial Royalties paid should be allowed as a cost in determining income taxes payable.

Corporate Income Tax as a Substitute for Royalty Revenues

Alberta's existing low royalties cannot be justified by the argument that the oil industry pays for all its service and infrastructure requirements through income taxes. It does not because:

1. Too large a share of income taxes goes to the Government of Canada, to be distributed across Canada.
2. Alberta corporate taxation levels are low.
3. National and international corporations are required to allocate executive administrative, legal, engineering, sales and working costs across various operating profit centres and these allocations often have a significant impact on taxable profits earned on a particular operation. Also internal product flows often require internal pricing allocation to be made which, in the case of semi-processed goods, can be highly variable and effect revenues and profits significantly.

So we are left with the need to increase revenues directly to the Province of Alberta through royalties or other similar direct charges to the industry.

Distribution of Revenues between Governments

The Province of Alberta should receive the majority of government revenue from oil sands development because:

1. Alberta owns the resource.
2. Albertans directly experience the environmental impacts to water resources, provincial forest lands, fish & wildlife, air quality etc. although the air and water impacts do extend beyond provincial boundaries.
3. Alberta has to provide infrastructure to support the developments (highways, schools, hospitals, municipal infrastructure etc.)
4. Albertans are directly impacted by the overcrowding and overheated economy, and cost inflation created by these projects.
5. Alberta has to provide services to the people employed in the oil industry (health care, education, housing etc.)

That is why, when we look at various alternate forms of collecting government revenues, the corporate income tax model is less desirable than direct royalty payments.

In some jurisdictions, with a single taxing government like the United Kingdom, they can avoid royalty payments altogether and simply impose a 31% Income Tax.

In Canada, where income tax is collected by the Government of Canada, as well as the Province of Alberta, heavy reliance on corporate income taxes to raise revenue distributes a disproportionate share of the available oil sands revenues to the rest of Canada, leaving Alberta a relatively small share with which to fund the huge infrastructure and service

requirements of the industry.

Structural Deficiencies in the Existing Alberta Royalty System

In addition to the overall revenue deficiencies in the present Alberta oil sands royalty system, it does not meet the following strategic criteria:

1. It does not balance investment incentives in the form of low royalties with higher royalties during times of high prices and profits.
2. It fails to limit the period of token (1%) royalties with production or profit caps so companies are driven to expand continuously to avoid higher royalties.
3. It imposes a burden of project risk on the Province without a proportionately balanced opportunity for enhanced revenues in periods of high profitability. The Province does not receive any reward for its risk. It is quite probable under the current system that never ending project expansions will extend the 1% royalty indefinitely. Project payouts may not be reached for decades if world oil prices decline below W.T.I. US \$40 and project costs continue to rise at current rates of increase.
4. It does not compensate Albertans for the environmental degradation being seen on provincial public lands, for the inflationary pressures being caused in the Alberta economy, for the huge volumes of fresh water being consumed or for reduced air quality. Ordinary Albertans are not being compensated for the reduced quality of life in the Province.
5. It wrongly assumes that much of the revenue lost will be recovered through provincial income tax. Such is not the case because Alberta has low levels of corporate income tax, with generous resource allowances. Furthermore, the corporate income tax system is fraught with leakage, whereby revenues earned in Alberta may be offset by the cost of corporate activities in other jurisdictions.
6. The industry sometimes claims that the low royalties are adequately supplemented by lease bonus bids. This is not so. Many of the leases currently in production were issued years ago when the Province received insignificant bonus bids for oil sands leases. Furthermore, bidding on oil sands leases is highly dependent on the strategic location of the lease as well as on the estimated volume and quality of the oil sands resource on the lease. Not all lease sales will attract significant bids. The best leases have already been issued so there will be a significant decline in bonus bids in future years. Furthermore, preliminary estimates of bitumen volumes on a lease are often conservative and it is common for detailed exploration by the new owner undertaken after the lease has been acquired to show an increase in bitumen volumes by 30% or more above presale estimates. These large additional volumes are free of any bid cost. Finally, it should be noted that a 400 million dollar bonus bid amounts to 40 cents a barrel on a lease containing 1 billion barrels of bitumen.
7. It makes no provision to reward the efficient operator or assess the inefficient operator for his waste. One company may take a superior lease and operate it unprofitably. That company will pay very little royalty. Another company may have a poorer lease but operate it efficiently to earn a good net revenue. That company will pay more royalty. There can be significant differences in net revenues per barrel generated between different companies.

8. It fails to place any limits or cap on project capital costs eligible for inclusion in royalty credits. There is a large disparity in the capital cost per daily barrel of production from project to project. Some projects have a capital cost in the area of \$50,000 per daily barrel while others have a capital cost exceeding \$100,000 per barrel. Capital costs exceeding \$80,000 per barrel should not be allowed without detailed justification and approval.
9. Under the existing royalty guidelines if an oil sands project with an unrecovered balance is sold the unrecovered balance remains available to the new owner even if the previous owner received a sale price such that he recovered all costs and made a large profit.
10. Research costs can be claimed and recovered from royalties. However there is no provision whereby the Province receives any ownership in intellectual property that may result from such research. If royalty funded research generates patents, copy rights or licensable industrial technology, the Province should receive at least 49% ownership.

Recommendations

1. All currently operating oil sands projects should have production capped at current regulatory approval levels. In other words, no more regulatory production increases should be given to presently operating projects. They can of course continue to expand up to their existing regulatory approved production limits. All new production levels would require the operator to agree to pay for the new production under a new royalty system.
2. Priority should be given to granting approvals to new entrants for new projects up to a regulated production level of 300,000 barrels daily, provided applicants agree to increased royalties under a new royalty system.
3. Implement a new Royalty System for all newly authorized production structured somewhat as outlined below:

W.T.I. (\$U.S./Bbl Average Monthly Price Weighted by Daily Price x Production	\$C Royalty Percentage Charged on Gross Revenue in \$C Calculated Monthly	Additional Petroleum Revenue Tax on Project Net Revenue after Royalties
0.00 to 19.00	5.00%	0
19.01 to 38.00	9.00%	0
38.01 to 57.00	12.50%	12.5%
57.01 to 76.00	12.50%	25.0%
76.01 plus	12.50%	37.5%

At W.T.I. Prices above \$US 38.00 both the Royalty % and the Additional Petroleum Revenue Tax will be charged.

4. A new oil sands lease transfer or assignment fee should be charged to recover some revenue from continuously expanding operations that buy out undeveloped leases and operate them at nominal royalty rates. The assignment fees should be based on the most current published estimates of bitumen volumes at a charge of \$C1.50 per

- proven bbl and \$0.75 per bbl of probable bitumen reserves.
5. Water will be the limiting factor on future oil sands production. An absolute priority should therefore be given to water recovery rates (water use efficiency) with each successive regulatory approval being held to a slightly higher standard than the previous approval. All existing operations should be required to continuously improve their water use efficiency to best in practice standards on an urgent, regulated time line. Projects that fail to meet water efficiency targets should be charged \$C0.20 per cubic meter for the incremental volume used as a result of their failure to meet the targets.
 6. All oil sands operations should be required to clean (scrub) and dehumidify 80% of all carbon dioxide gas exhaust (all major exhaust points) and deliver the cleaned gas in pipe to one approved site exit point. This will facilitate delivery to a pipeline connection for export to sequestration sites. This should be done without compensating the operator and with no payment for the gas. Based on the principle that the "polluter pays" operators using the existing royalty system should not be allowed to charge the capital or incremental costs as eligible costs. All operators would receive any carbon credits available for their reduced gas emissions once the gas is removed and disposed of. Operators who fail to provide the clean volumes required would be charged an environmental penalty of \$C15 per tonne for gas released above the allowed 20%.
 7. Large existing mine operators have accumulated huge tailings ponds which will be very difficult and costly to reclaim. These same operations have had the benefit of low royalties which they will continue to enjoy for years. They can therefore afford to fund a major effort to clean-up their tailings ponds. Each company should therefore be required to pay an annual fee of \$C0.30 per cubic metre based on the volume of tailings in storage on December 31 each year. Seventy percent of these monies would be placed in a dedicated and segregated tailings pond reduction and reclamation fund controlled by the company. The other thirty percent would be placed in a multi company oil sands tailings pond research fund dedicated to solving technical dewatering, tailings water treatment, sludge treatment and reclamation issues.
 8. It may be argued that eventually the property tax assessment for these large plants will enable the municipality of Wood Buffalo to pay for municipal infrastructure required to service these developments - municipal roads, water and sewer to new housing subdivisions, as well as to provide municipal services - fire, police, garbage pick-up and disposal, sewage treatment and disposal, parks and recreation etc. But in the short term, these costs are being subsidized by the Province. Will present provincial infrastructure subsidies ever be repaid by the municipality? By the industries themselves? The property tax structure for these huge projects needs to be fully reviewed. Should provincial assistance be made in the form of low interest loans to be repaid from future property tax revenues?

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Submission
To
Oil Sands Royalty Review Panel
With
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