

Alberta Royalty Review

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Remarks

by

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Summary:

- **The Alberta take should be higher in high profit scenarios.**
- **The favourable handling of cost recovery should be maintained.**
- **The fiscal terms should have greater incentive for cost savings.**
- **Consider royalty credits for a reduction in the intensity of the consumption of natural gas or water in the extraction and upgrading.**
- **A well designed R-Factor system increases the chance that both government policy objectives and investor requirements can be achieved over a wider range of cost and oil price scenarios.**

Alberta can receive more under high profit scenarios and still maintain a high degree of alignment with the industry.

Mr. Chairman and other honourable members of the panel.

Good afternoon.

Thank you for the opportunity to speak.

My comments will focus on the oil sands terms.

I am a resident of Alberta and Canada and proud of both.

My most current activities have been the design of fiscal terms to bring international oil companies (IOC) back into the upstream in the Middle East. The work has involved the review of international terms, the investment criteria of IOCs and the design of terms that are workable over a wide range of conditions.

I want Alberta to continue to be a very attractive place to invest. However, the existing oil sands terms could use a tune up.

The Alberta take should be higher in high profit scenarios.

The royalties and taxes on the oil sands rank well towards the “lighter” end on the spectrum throughout the world. This is highlighted in the context of local conditions or risks whether it be rebels or fiscal and regulatory stability. (Nigeria, Venezuela, Russia). A “government take” of about 50% is comparable to that for the Gulf of Mexico. A large new offshore project involves high capital, time lag before revenues are generated and harsh environment, not unlike the oil sands. However, the production profile for an oil sands mining project may be flat for many years versus a short plateau followed by a prolonged decline.

Opex is higher for oil sands but as the offshore field declines the unit opex can increase significantly. I think it is reasonable to say the uncertainties with the deep sub surface are somewhat less within the control

of management than the operating costs of a mining or a processing facility. The oils sands are being well treated relative to the Gulf of Mexico.

Host countries that have a progressive system (higher government take with higher profitability thresholds) see this as a reasonable treatment of the risk/reward. This is linked to the availability of cost recovery, for example, by the “cost oil” as defined in a production sharing agreement or by a reduction of royalties. After facilitating payout the host jurisdiction should share significantly in any upside after certain “payout” thresholds are achieved.

Government takes far higher than 50% can be achieved through competitive bidding, rather than being imposed by host jurisdictions. This involves bidding a financial parameter that applies for the term of the agreement rather than an up front bonus. Apparently, some of the most attractive blocks in North Africa have been awarded at government takes of more than 90%. There is no credible suggestion that Alberta can or should duplicate this.

However, it does demonstrate that some governments have been more shrewd in getting what the market will provide.

There is justification for Alberta to receive more, but this does not require disruptive changes.

The favourable handling of cost recovery should be maintained.

This is as much a strategic decision for Alberta and Canada as economic. I do not believe in peak oil, at least for several decades. If the best technology and project execution could be applied to the reserves in the Middle East it would be more than equivalent to the oil sands. Now, it is by no means certain what degree of development the Middle East will see or

that OPEC would decide to reassert market influence by a lower oil price. Other things could cause a period of lower revenue or higher costs such as conservation, a hiccup in the growth of China and India or air quality. Favourable cost recovery cushions the impact of such events. The long term interests of Alberta and companies that have a long term commitment to the oil sands are aligned in this feature.

The fiscal terms should have greater incentive for cost savings.

While I support cost recovery, for the reason given above, it can reduce the reward generated by cost savings. No one is being irresponsible in cost management. Those composing the projects are behaving as would be reasonably expected given the fiscal terms and the oil price levels plus, perhaps, the corporate strategy to maximize the footprint in one of the few areas in the world where there is access to large reserves. If the resulting marginal costs influence the cost for other projects in the province, such as government infrastructure or pipelines, is it possible the value creation is modest?

Market forces and possibly fiscal terms must start to act on these cost levels. While it might force some re-optimization of projects, this is healthy and in fact the players with the biggest long term plans should be the ones able to benefit most. In the longer term value added would probably be greater.

One positive thing about the loss of the accelerated CCA, dare it be said, is that the reward for a capital cost saving is somewhat greater in terms of higher NPV.

Consider royalty credits for a reduction in the intensity of the consumption of natural gas or water in the extraction and upgrading.

This rewards desired results. It is the other side of the same policy coin that levies \$15 a tonne on the generation of another unit of greenhouse gases.

The industry can select the specific technology or techniques.

An R-Factor based example is provided that is intended to demonstrate one of the more common and effective tools to achieve the objectives of government policy.

This example is not meant to be presumptuous or premature. However, when the panel drafts its report to the Government of Alberta some indication of what can be done, using one of the techniques available, might be useful. The specific cases and R-Factor design is only intended to be indicative of potential.

One of the more common methods to trigger, or delay, higher levels of government take is by the use of well designed R-Factors. The current trigger for the 25% royalty is based on the relationship of revenues to costs. This principle should be maintained. Observing the relationship between revenues and costs increases the chance that both government policy objectives and investor requirements can be achieved over a wider range of cost and oil price scenarios.

Define R as accumulated gross revenue divided by accumulated capex plus accumulated opex.

Consider the following terms;

5% minimum royalty on gross revenue or 10% of revenue minus costs, which ever is greater.

25% royalty rate when R hits 1.40 (the 25% is triggered considerably later than under the current terms)

30% royalty rate when R hits 1.70

45% royalty rate for R greater than 2.00

The following table shows NPV @ 10% real, IRR and government take for a theoretical mine plus upgrader under the current terms and the R Factor example. The specific numbers are not as important as the relationships. The Low case might represent a higher cost or lower revenue scenario. The Base case represents the intended business plan. The High case is the “this would be great” scenario.

	Rfactor BASE	Current	Rfactor HIGH	Current	Rfactor LOW	Current
NPV	2220	2428	4113	4985	204	309
IRR	13%	13%	17%	18%	10%	10%
Gov Tk%	57%	56%	63%	55%	57%	56%

- a) The R-Factor has been tuned so the cases most relevant to decision making, Base and Low, are not significantly disrupted.
- b) The Low case still benefits from the cost recovery and the fact that only lower levels of royalty are triggered.
- c) In the Base case Alberta gets more in royalties in the first 7 years, lower royalties in the next 3 years and somewhat more thereafter. (royalty payments are not shown in the table)
- d) In the High case the government take is 63% rather than 55%. However, the High case NPV for the investor is still well above the Base case. Alberta gets a larger share but it is still a clear win-win.

The 5% minimum royalty gives Alberta more revenue in the early years consistent with infrastructure requirements usually associated with a higher level of economic activity in the province and slightly improves the incremental economics of a cost saving. Alternately, this revenue could be used to increase drilling for conventional oil and gas or for incentives for NCG. The higher minimum is balanced by a higher trigger point for the 25%.

A well designed R-Factor requires;

- a) A wide range of cases used for the R-Factor design. Industry input is important. If the government makes it clear that change is coming the industry can provide some of the best input.
- b) Testing to verify the behaviour and workability of the R-Factor. Several logical, sound and thorough techniques are available.

The R-Factor design could be different for insitu, insitu plus upgrading, mining or mining plus upgrading. These possess different cost and revenue profiles. R-Factor design is intended to reflect these characteristics and can be a useful policy tool.

Conclusion:

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