

June 15, 2007

Alberta Royalty Review Panel
1100, 715 Fifth Avenue SW
Calgary, AB T2P 2X6

Attention: Mr. Bill Hunter, Chair

Dear Mr. Hunter

**Re: Small Explorers and Producers Association of Canada (SEPAC)
Recommendations to the Alberta Royalty Review Panel**

Summary of SEPAC's Broad Position on Alberta's Royalty Review

We thank the Alberta Royalty Review Panel for the opportunity to comment on this vitally important matter of public policy.

SEPAC is strongly opposed to any increase in the government's take from the petroleum industry. It is our opinion that moving in that direction will be counterproductive; driving away investment dollars that are needed each year to slow Alberta's rate of production decline and hastening the forecast drop in government revenues from the conventional petroleum sector. With the exception of the recent (January 1/07) elimination of the Alberta Royalty Tax Credit, SEPAC believes the current Alberta royalty and fiscal regime strikes a reasonable balance between the need for the government to receive a 'fair share' and industry's need to make an appropriate rate of return on its investments.

Having said that, SEPAC believes there are some areas where the existing royalty structure could be adjusted to further encourage needed investment, particularly in marginally economic reserves. In addition, we have some recommendations to streamline the current methods of royalty reporting, for example, by elimination of take-in-kind royalty payment for oil which we think will greatly reduce administration costs for both industry and government.

We should also point out that prior to the creation of the Royalty Review Panel, SEPAC was invited by both the previous and current Ministers of Energy to make recommendations to the government on where to 're-invest' at least some of the \$300 million dollars the government expects to take annually from industry as a result of adjustments and phase outs of certain royalty programs announced in August of 2006 and the outright cancellation of the ARTC effective January 1 of this year. Our comments and recommendations which follow are a response to that invitation as well and will be forwarded to the Minister of Energy.

Background on SEPAC and the Junior Oil and Gas Sector in Alberta

Our Association, established in 1986, represents approximately 450 corporate members. 75% are junior oil and gas companies and the remainder is companies who supply goods and services to the upstream petroleum industry. Our members represent about 34% of Alberta's 'active' operators (defined as those who drilled at least one well in Alberta in 2006). Collectively our members operated nearly one fifth of Alberta's new wells drilled last year and financed many more through non operated working interests.

Alberta has been the birthplace of a junior oil and gas sector that is unique in the world. To illustrate how unique: there are more publicly traded oil and gas companies listed in Canada (TSX and TSX Venture) than all the other stock exchanges in the world combined. The vast majority of these listed companies are junior and intermediate sized companies virtually all of whom are active in Alberta. But the publicly listed companies are only part of the story since much of the junior sector is unlisted companies; two thirds of SEPAC's members are not publicly traded. Collectively the junior segment of the upstream petroleum industry invests billions of dollars into the Alberta economy exploring for more oil and gas. In fact, a typical junior invests an additional two dollars (raised through debt and equity) for each dollar of internally generated cash flow.

The junior sector remains strongly focused on production of conventional oil and gas in Alberta although some are now expanding into unconventional gas and *in situ* oil sands projects. Alberta's conventional oil and gas reserves are increasingly defined by their small size and rapid production declines. Over 60% of Alberta's oil wells produce less than 12 barrels a day (source: CAPP). As for natural gas, the average production of a new well has declined from 750 mcf per day ten years ago to only 200 mcf per day (source: Ziff Energy Group). A producer now has to drill four wells to get the same production as he could previously get from a single well and of course costs to drill a single well itself have risen enormously during the past decade.

Farmers, ranchers and residents of small towns and rural communities across the Province benefit in many ways from petroleum industry investment and operations in their areas. Apart from the benefits all Albertans receive through the billions of dollars in royalties and taxes paid annually to the Provincial government by the petroleum industry, many rural Albertans supplement their income through full time or seasonal employment in the industry, all benefit from the local municipal taxes paid by industry and surface lease rentals are usually a welcome supplement to traditional incomes for rural landowners. SEPAC estimates that 85% of the cost of operations for a conventional oil or gas well is spending that stays in rural Alberta, not downtown Calgary. Each well that is commercially viable and producing injects some \$25,000 a year into the surrounding rural economy through wages and purchase of local goods and services paid by the well operator.

All oil or gas wells will produce at lower rates over time and eventually operating costs exceed net revenues and wells are shut in and abandoned. Extending the producing life of wells and ensuring as much of the deposit as possible is recovered using sound production practices results in prolonged prosperity to the local economy. Small producers are the right size and have the right cost structure to profitably develop and produce Alberta's small conventional hydrocarbon deposits for many decades into the future. They are also the natural buyers of mature oil and gas plays as the major producers take advantage of their own scale and size by focusing more on oil sands and large unconventional gas plays such as CBM and shale gas.

Historical Context for Alberta's Royalty Review

In 1974 relations between Alberta and Ottawa erupted in a fiscal and constitutional battle over revenues from oil and gas. Alberta upset decades of relative stability in the royalty regime by substantially increasing its take by introducing new royalty rates. Ottawa responded to this threat to its own revenue base by declaring that the new provincial royalties would not be deductible for federal income tax purposes. The private sector was facing a ruinous situation being squeezed between two levels of government.

The Ottawa-Alberta fight over oil and gas revenue and jurisdictional control culminated in the 1982 National Energy Program which caused considerable economic devastation in Alberta and which took years to recover from. Many programs were introduced during this period by Alberta to encourage activity in selected areas: ARTC, "New" oil, "Third Tier" oil, flared solution gas, reactivated wells, low production wells, experimental projects, EOR, horizontal wells and so on. These programs yielded some measure of desired results and continue to yield results today.

It has taken more than three decades to restore the balance between the federal/provincial government "take" from the petroleum sector after the battle that first erupted in the 1970s. The federal government has just recently restored full deductibility of provincial royalties against federal income tax and effective January 1, 2007 will tax the oil and gas industry at the same corporate rate as other industry sectors in Canada. This history suggests that caution should be exercised by Alberta when unilaterally considering to up its share of total government "take" from the petroleum industry.

Alberta Royalty Tax Credit (ARTC)

Alberta's Finance Department and Auditor General in recent years cited audit complications and costly overhead in administration of ARTC and the government cancelled this program January 1, 2007. Cancelling ARTC significantly affected the smallest producers by eliminating 5% or even 10% of cash flow and reserves value. The Review Panel will by now be familiar with the *Van Meurs* study showing how cancellation of ARTC impacts Alberta's relative investment attractiveness: on Third Tier oil dropping from 52nd to 209th out of 324 regimes and on New Gas dropping from 48th to 212th out of 258 regimes studied.

To the extent ARTC cancellation deprives industry of cash flow that could have been invested in developing otherwise uneconomic reserves, the unintended effect of this decision may well reduce future royalty income not sustain or expand it. The current "savings" may be a costly illusion for future taxpayers in Alberta.

SEPAC urges that the government return these ARTC "savings" to industry since they can far more effectively be invested by industry in the search for more oil and gas and leveraged to bring in more investment; e.g. note our earlier comment that each dollar of net cash flow retained by the typical junior results in two additional dollars being reinvested in Alberta's petroleum resources. These recovered ARTC sums could be used to expand the scope of existing programs, such as the current Low Productivity Royalty Reduction Program or the Third Tier Exploration Well Royalty Exemption, or perhaps more boldly, reduce or eliminate outright the royalties paid on extremely low productivity wells e.g. wells producing five barrels a day or

less. ARTC “savings” should also be considered for redirection to additional government funding for the EUB budget; industry pays for more than half of this budget.

We expand on these suggestions below, but also want to take this opportunity to offer suggestions on other areas of Alberta’s royalty system which we think are worthy of consideration.

Gas Royalties

1. Low Productivity Royalties

One of the concerns for SEPAC members is the high royalty rates paid in the early life of production. Many SEPAC companies are developing shallower gas plays where the initial production rates for wells start at a higher rate, and then drop off quickly, declining between 30% and 50% in the first year of production. Over time, these wells will stabilize and decline more slowly. Overall, the recoverable reserve is not large, and if the rate of take for these wells were averaged out over time in the first few years, the average rate would be subject to a lower royalty than is incurred during the initial flow period. The economics of these plays are heavily weighted to these initial flow periods when cash flow is critical to the investor to recover the large initial investment. The economics of drilling these plays is marginal at best, and the economic value is sharply eroded by the high early royalty rates.

We propose two alternatives for royalty modifications that we believe will promote the development of these types of reserves:

- i) Develop a mechanism to average the royalties for some initial period of production, that better reflects the average production rate; or
- ii) Modify the low productivity calculation for new gas royalties that provide an incentive for companies to invest in these low productivity plays. This modification could take the form of extending the minimum royalty of 5% to a higher production rate than the current, and increasing the royalty rate from this new minimum in the same manner as the current formula. We believe this merits some serious consideration.

Alberta recognized years ago that its declining conventional oil reserves deserved incentives for low productivity wells and responded with royalty reduction programs. We believe the conventional natural gas industry has now reached a similar stage of maturity and decline and Alberta needs to do more here, particularly to encourage more exploration drilling for natural gas.

2. Custom Processing – The “Lost GCA”

“Allowable Costs”, also called “Gas Cost Allowance” (“GCA”) refers to costs that an owner of a gas processing facility is allowed to claim as a deduction from royalties for the eligible capital investments made to construct facilities required to get gas production to a marketable state from the wellhead to the sales point, and generally include gathering systems, compression, and processing. The amount of these allowed costs that is “lost” (the “Lost GCA”) occurs when custom gas processing for non owners of the facility is provided at a facility, and owners of the processing facility are required by the government to allocate all facility capital allowed costs, including the unused facility capital, to third parties based on proportion of throughput between

owners' gas and third party gas. Industry practices however for determination of processing fees (JP-05) specify capital charges be calculated on the capacity used by a third party, resulting in a lower capital fee for custom processing than if it were determined based on throughput, especially in an underutilized facility. As a consequence, facility owners will add a Lost GCA fee to the processing fee to compensate the owners for the loss of the capital portion associated with unused capacity. This results in higher processing fees for facilities with unused capacity, the very facilities that need custom users to maintain throughput efficiency.

SEPAC companies are typically custom users, and generally pay fees to have their gas processed by others. If the government were to modify its methods of allocation of facility capital allowed costs from throughput to capacity used (like industry practice), this would eliminate the Lost GCA portion of the fee. This is a request the industry has made to the government since the first fee methodology report was issued in 1990. Lower fees will provide greater incentive for producers, especially smaller companies, to seek custom processing alternatives, and will promote the use of existing capacity, rather than for companies to build their own (and likely redundant) infrastructure.

Oil Royalties

1. Take-in-kind payment

Alberta collects its oil royalties through "take-in-kind". Each month, operators calculate the royalty volume for each well, and arrange to have this volume delivered to the account of the Department of Energy. The Department of Energy then has this oil sold for them through a marketing agent, and Alberta is paid directly for sale of this royalty oil. In 2006, Alberta introduced new measures that increased administrative complexity and associated costs for operators and now include penalties for incorrect deliveries of volumes (even for errors as small as 0.1 m³).

During the battle over control of resources in the 1970s between Alberta and Ottawa, Alberta initiated take-in-kind as a strategy to strengthen its position as "owner" of the petroleum resource. This constitutional justification is no longer relevant yet it lingers on for conventional oil royalties even though today Alberta receives much larger revenues from natural gas and bitumen royalties where the take-in-kind system is not applied. The cost to Alberta and industry for keeping take-in-kind cannot be justified any longer and it should be eliminated. Alberta can always keep the right to revert to take-in-kind if it wishes to preserve its constitutional "ownership" argument.

SEPAC recommends collection of oil royalties be administered like natural gas via the Petroleum Registry which is regarded as a great success by both government and industry.

2. Oil Royalties – Very Low Productivity

Our research suggests that (assuming all production is classified as post March 1974 "New" oil for royalty calculation) wells producing five barrels per day or less may generate only about 0.23% of Alberta's oil royalty income*, yet represents 25% of the total number of oil wells requiring calculation and reporting to government. Substantial cost savings for industry and government could be realized perhaps exceeding the amount of royalty collected if the royalty on such very low volume wells was waived.

* and a virtually insignificant portion of total royalties taken from all hydrocarbon resources: gas, conventional oil, heavy oil, bitumen.

3. Oil Royalties – Three Tiers

In Alberta there are three levels of royalties relating to pool vintage. “Old” oil is from pools discovered prior to March 31, 1974. “Third Tier” oil is from pools discovered since 1992 and “New” oil is from pools discovered between these two dates. Old oil pays the highest royalties and Third Tier oil pays the lowest royalties. In the interest of simplifying perhaps it is time to reclassify Old to New.

4. Oil Royalties – Low Productivity Well Royalty Reduction

See comments above on using ARTC “savings” to enhance the parameters of this program. Also see comments above on waiving the royalty on very low productivity wells e.g. 5 barrels per day and under.

5. Oil Royalties – New Waterflood Projects

In 2006, the Department of Energy made a presentation to SEPAC identifying targets for potentially recoverable waterflood reserves which, in the DoE’s opinion, were not being addressed in a very aggressive manner by industry. SEPAC urges the Panel and the DoE to consider using the royalty system to encourage more investment in waterflood projects.

6. Oil Royalties - High water cut

Saskatchewan has a program which allows a 2.5% reduction in royalties to compensate for wells which produce a high water cut and which are thus more expensive to operate. This would be something we suggest should be looked at carefully for adaptation to Alberta.

Environmental Goals Advanced by Royalty Incentives

CO2 Projects: Sequestration of CO2 will become increasingly important as a greenhouse gas mitigation measure and the government should study whether further incentives under the royalty system would accelerate use of CO2 for both EOR and GHG reduction initiatives.

Reductions in Fresh Water Use: Industry is being encouraged to move towards less use of fresh water in drilling and production operations. The royalty system also could provide incentives for this objective.

Oil Sands Royalties

The existing regime has been successful in its intended purpose of attracting investment to Alberta’s oil sands. Some SEPAC members participate in oilsands development through several *in situ* projects. These projects need to continue to attract investment capital particularly as new and untested methods of recovery continue to be deployed. Oilsands royalty revenue has grown rapidly in recent years as a result of new projects coming on stream and more projects reaching the ‘post payout’ stage of royalty calculation. We believe the existing regime has provided and will continue to provide huge benefits to Albertans. Any significant

change is likely to negatively impact a stable and successful business environment and SEPAC does not support such changes.

Bonuses and Land Rental Fees

Increases in government 'take' via petroleum royalties can be expected, all other things being equal, to reduce the government's up front take from Crown land sales. Companies bid on land after considering a number of complex interconnected factors including strategic position, competitive advantages, land access complications, risk of failure, and forecast cash flows (commodity prices, operating costs, capital costs, risk of failure, royalty costs, taxes, etc.) This inverse linkage between the government's upfront land bonus payments and royalties should be carefully weighed by the Royalty Review Panel.

Conclusion

The willingness of the Province of Alberta to maintain a stable, predictable fiscal and royalty structure that provides an investment climate attractive to small petroleum producers will have considerable impact on meeting the challenge over the next few decades of extending the life of Alberta's conventional oil and gas reserves as well as supporting the move of smaller companies into unconventional and oilsands resources.

Thank you for the opportunity to offer our comments to the Royalty Review Panel. We would be pleased to elaborate in further discussions.

Sincerely,

Gary Leach
Executive Director

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Minister of Energy, Mr. Mel Knight
Deputy Minister of Energy, Mr. Dan McFadyen
CAPP, Mr. Greg Stringham