Technical Royalty Report #3:
Alberta’s Conventional Oil and Gas Industry
- Impact of Potential Royalty Change on Industry Activity -

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

Introduction:
This report is the third of a series of technical reports describing issues related to the fiscal system for Alberta’s conventional oil and natural gas. The purpose of the report series is to provide information and to invite comment as part of the Government of Alberta’s public review of the royalties and taxes applied to the province’s oil and gas resources. Another report series provides information on the Alberta oil sands industry. The purpose of the present report is to describe the potential impact on activity that could be expected for a change in royalties.

Technical Report OG#2 demonstrated that the overall expected value from drilling a conventional oil or natural gas well in Alberta is clearly attractive. The report also compared government/resource owners’ shares, showing the shares in the United States to be somewhat higher than those in Alberta.

A further important consideration in this regard is the potential impact on industry activity – investment and employment. If royalty rates were to change there may be a corresponding change in industry activity.

That a change in royalties would likely have an impact on activity results from two realities, one that can be considered trivial and the other significant. The trivial impact results from the fact that there will always be some well that is on the margin, no matter how high or low the applicable price or royalty rate. In these situations the threat to investment activity is more related to the inherent project economics than to the royalty structure.

The more significant factor however relates to the economic expectation for the median well. This is to contrast the net economic benefits for the median (the most frequently occurring) well with those for the average (Swanson Mean)[1] well. The Swanson Mean well represents the overall expectation whereas the median well reflects the most commonly occurring result. Consider the following example:

	Drilling Program										Median	Average
Well #	1	2	3	4	5	6	7	8	9	10	n/a	n/a
Reserves	2	2	2	2	2	0	0	1	4	35	2	5

[1] See Technical Report OG #2.

The example shows that the most commonly occurring expectation is a reserves discovery of 2 units whereas the average expectation over the entire drilling program is 5 units. This situation reflects the fundamental nature of exploration economics in the oil and gas industry world-wide.

Report OG#2 showed the average expectation for Alberta to be clearly positive. What that report did not show (because it was beyond the scope of the report) was that the median well is marginal to sub-economic. If the median well were economic it would suggest that an increase in royalty rate could have minimal or no impact on drilling activity if the median well remained economic after this change. Since the median well result for Alberta is marginal to sub-economic we can expect that a royalty rate increase or price decrease would have some negative impact on drilling activity.

Two approaches are identified to help quantify the potential impact of a change in royalties on activity. The first is to examine the economics on the margin through a consideration of the median well; this will provide insight into how the most likely wells may be impacted; that is, are there a large number of wells on the margin or relatively few wells. The second approach is to empirically test the responsiveness of activity to a change in royalties through analogy with a change in price.

Median Well Economics:

In Technical Report OG#2 it was observed that the expected economics of drilling in Alberta are attractive. Having identified that the expected economics are positive, a logical next question is whether the typical/most-frequently-occurring outcomes are also positive. This will shed light on the potential impact of increased royalty rates on drilling activity. The median well represents the most likely outcome of drilling a well without acknowledging the positive contribution that larger discoveries have on the overall economics.

If the median well is profitable at a rate of return above the cost of capital (acknowledging risk), then it can be expected that activity would be unchanged. If the median well is not profitable at a rate of return equal to the cost of capital, then activity can be expected to decrease. This can be thought of as a marginal revenue and marginal cost argument. The marginal revenue is represented by the revenue earned by the median well. Similarly the marginal cost is represented by the costs of drilling the median well. If the median well adds to overall profitability more wells will be drilled.

Tables 2 and 3 respectively present the summarized median well results for natural gas and conventional oil wells in Alberta using the assumptions outlined in Technical Report OG#2. As suggested above, the results show the median well to be only marginally attractive and in general to not generate a 10 percent full-cycle full-risk rate of return including the costs of unsuccessful wells. This suggests that at the price and costs assumed in this report, a fall in price or an increase in royalties can be expected to translate into reduced industry activity. This is consistent with an 11% decrease in oil and gas well licensing reported by the EUB for January and February of 2007 relative to the same months of 2006. It is also consistent with a 21% decrease in the number of successful wells completed in January and February of 2007 relative to the same months of 2006. For these months the prices of natural gas averaged $10.04/Mcf and $7.78/Mcf in January and February of 2006 respectively and $6.61/Mcf and $7.19/Mcf for January and February of 2007.

TABLE 2 – NATURAL GAS MEDIAN WELL (EMV – PRICE $6.39/MCF)

Alberta Gas							
	Modelled Results						
Area	Well EUR Bcf	Average Revenue $/Mcf real	EMV $000 real	EMV $/Mcf real	EMV 10% $000	EMV10% $/Mcf	$PFR_{10\%}$
PSAC 1	3.90	7.56	2293	1.01	141	0.06	1.03
PSAC 2	0.96	8.35	597	0.82	-99	-0.14	0.96
PSAC 3	0.12	6.17	-62	-0.58	-132	-1.24	0.63
PSAC 4	0.24	6.07	61	0.32	-54	-0.28	0.90
PSAC 5	0.36	6.65	52	0.20	-139	-0.54	0.83
PSAC 6	0.55	6.15	474	1.53	258	0.83	1.57
PSAC 7	0.51	6.61	162	0.55	-28	-0.10	0.96
Total	1.18	7.26	642	0.49	-50	-0.06	0.98

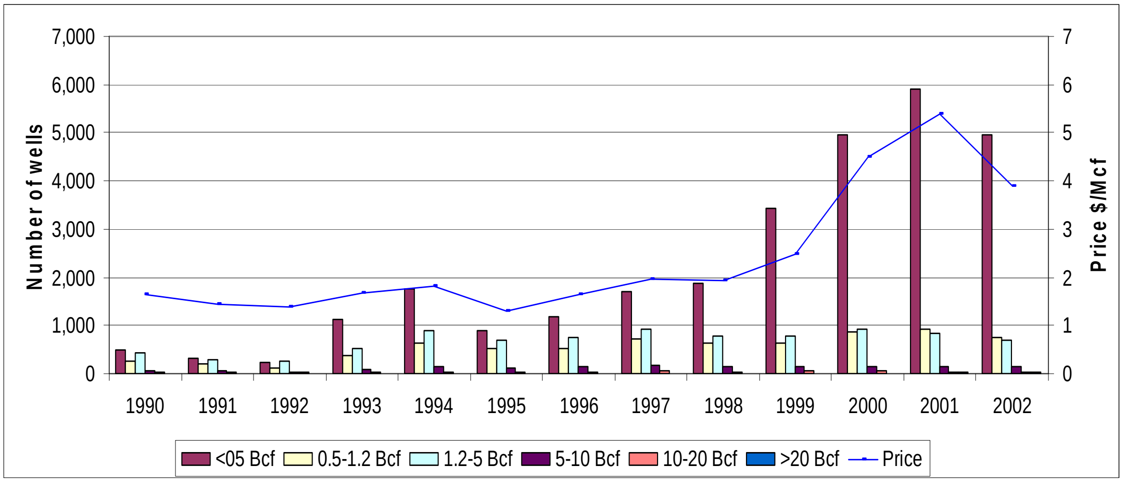
TABLE 3 – CONVENTIONAL OIL MEDIAN WELL (EMV – PRICE $51.45/BBL)

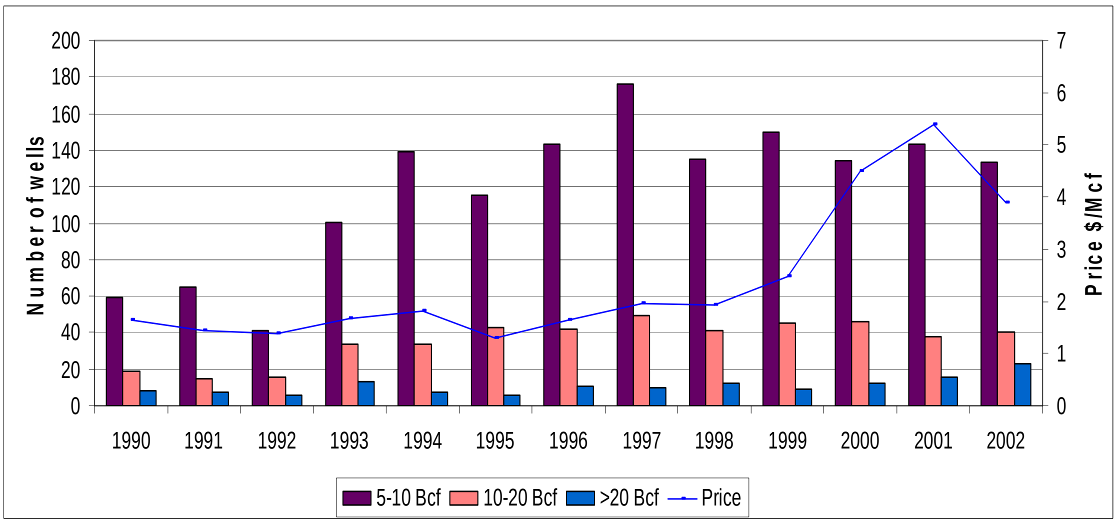
Alberta Oil							
	Modelled Results						
Area	Reserves Per Well Mboe	Average Revenue $/boe real	EMV $000 real	EMV $/boe real	EMV 10% $000	EMV 10% $/Boe	$PFR_{10\%}$
PSAC 2	63.77	43.47	-588	-12.15	-768	-15.88	0.55
PSAC 3	62.72	34.76	194	3.48	37	0.66	1.05
PSAC 4	32.27	39.06	-23	-0.89	-108	-4.17	0.81
PSAC 5	47.33	44.77	-132	-3.89	-303	-8.91	0.72
PSAC 7	76.38	44.31	100	2.10	-72	-1.51	0.93
Total	58.88	40.76	-63.95	-1.69	-218.98	-4.74	0.80

Figures 1 and 2 below from Technical Report OG#1 show that changes in activity have been almost exclusively tied to low reserve wells. This is explained through the fact that the wells that are being drilled in response to short term changes in prices are the wells that are on the margin. That is, the wells with small reserves, high per unit costs, and rates of return that are close to investors' hurdle rates. These are the class of wells that are first impacted by a change in profitability. From Figure 1, it is observed that because improved economics through high prices there are a large number of these low reserves wells.

An additional observation that can be made from Figure 2 is that there appears to be some fixed level of good prospects that can be identified and developed on an annual basis that are relatively independent of prices. The important thing to note is that changes in price and activity do not seem to affect these targets.

FIGURE 1 & 2 – ALBERTA GAS PRICES AND WELLS DRILLED 1990-2002[2].





Source: Alberta Energy

Figures 3 and 4 show the change in reserves for the median well over time compared, respectively, to natural gas prices and the number of wells drilled.

[2] Note: There is a difference in the scale for these two charts. The lower chart is a subset of the upper chart in order to allow the trend in larger wells to be observed.

FIGURE 3 – ALBERTA RESRVES PER MEDIAN WELL AND PRICE

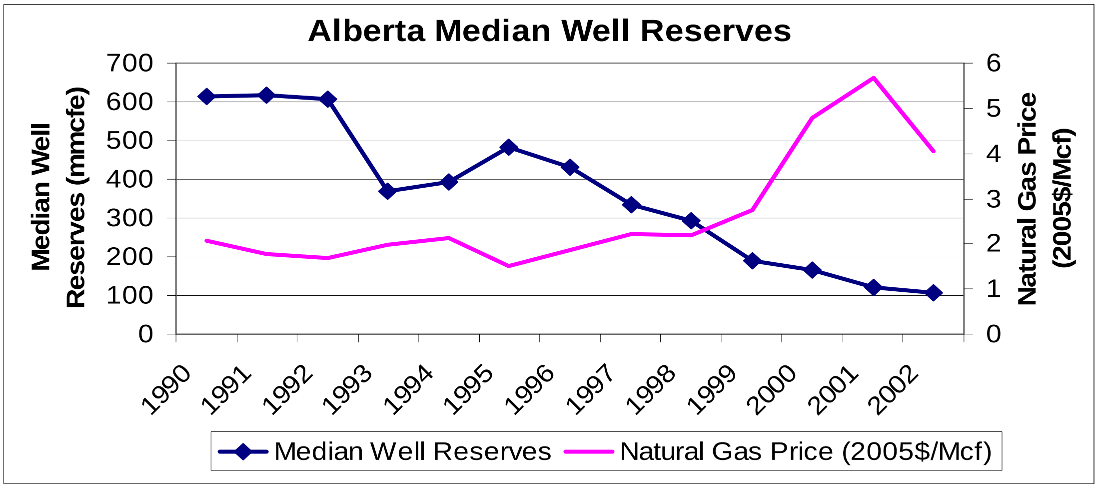
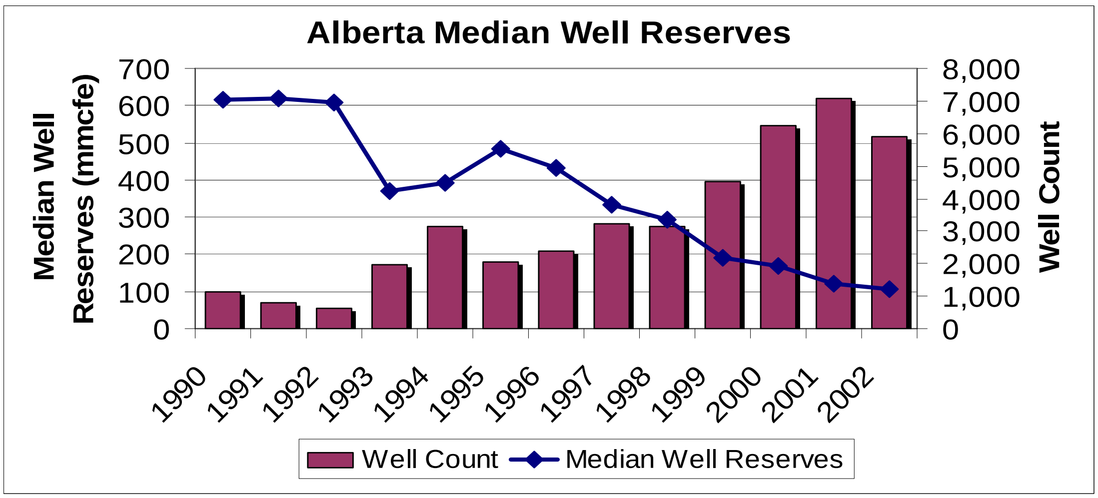


FIGURE 4 – ALBERTA RESRVES PER MEDIAN WELL AND DRILLING



In 1990, the median reserves per well were 615 million cubic feet (MMcf). By 2002, this number had dropped to 107 MMcf. Of interest is the high correlation between wells drilled and median reserves. There is almost a one to one correlation. That is, increased drilling is clearly lowering the median reserves per well. This is to be expected as there are naturally many more small pools than large pools. With increased industry profits due to increased prices it has become economic to produce ever smaller pools, thereby lowering the median reserves per well.

While it appears reasonably clear that any change that lessens the economic attractiveness at the margin would have a direct impact on the number of wells being drilled, it is correspondingly evident that a reduction in the number of wells being drilled would result in an increase in the median reserves per well and this would improve the economics of the median well. Similarly, these consequences do not consider any possible improvements that might occur to the economics based on lower costs from less demand for oil and gas well services.

Empirical Measurement:
As royalty changes are infrequent, data does not exist to empirically and precisely identify the direct impacts that a change in royalty may have on activity. Such impacts however may be estimated by comparing the impact of prices on activity. A change in royalties will ultimately impact the net revenue from a well. In this regard a change in royalties is similar to a change in price. Data is available to estimate the impact that price has on activity. A simple linear regression was used to estimate the price responsiveness, or price elasticity, of drilling activity as measured by the number of wells spudded.

Actual drilling activity in Alberta is highly seasonal due to the weather. In parts of Alberta the spring melting makes the ground too soft for heavy equipment. As such, drilling activity is highest in the winter, falls off in the spring, and tends to recover over the summer and fall. For this reason a de-seasonalization of the data is required. This de-seasonalization was accomplished through the use of dummy variables for the various months. A log-linear equation was chosen in part to facilitate easier interpretation the results.[3] The equation:

$\ln W = \beta \ln P_g + \alpha_i D_i$ is estimated using monthly data for the period 2001 to 2007,

where:

$\ln W$ is the natural log of wells spudded;

$\ln P_g$ is the natural log of the price of natural gas; and,

D_i is a dummy variable with i representing the various months (i.e., i = January to December).

The results of this regression are presented below in Table 4 below. These results show a very strong correlation with an R square of over 99%. The results suggest that for every 1 percent change in the price of natural gas there is a corresponding change of 0.58 percent in the number of wells drilled.

[3] The log linear specification is used to generate elasticities - the percentage change in one variable for a percentage change in the other variable. It can be shown that the partial derivative of the log-linear equation is precisely this elasticity.

TABLE 4: REGRESSION RESULTS – D RILLING ACTIVITY

Number of Observations = 73		
R square = 0.998884		
Variable	Estimated Coefficient	T - Statistic
ln p_g	0.582703	6.120908
January	6.546522	32.13531
February	6.667734	33.43822
March	6.21843	30.98825
April	5.151805	25.94004
May	5.903082	30.0796
June	6.135398	32.11297
July	6.467962	34.60837
August	6.305146	33.89964
September	6.150419	33.24323
October	6.297274	33.91601
November	6.226067	31.43625
December	6.269278	31.32572

While the price elasticity of drilling is interesting, it is the responsiveness of drilling to a change in net revenue that is needed. To extrapolate from price to net revenue requires an understanding of the impact of prices on net revenue.

Net revenue is defined as gross revenue less costs, royalties, and taxes. Gross revenue is simply price times production. Royalties are price times production times the royalty rate. Taxes are equal to gross revenue less costs less royalty multiplied by the tax rate. Treating production and costs as independent of price[4], the change in royalties can be seen to be the change in price times the royalty rate, and the change in taxes as price minus the change in royalties times the tax rate. Given the effective royalty rate of about 20% and a combined federal and provincial corporate income tax rate of roughly 30% suggests a 1% change in price results in a change in net revenue of 0.56%.[5]

Combining these two results (price elasticity of drilling = 0.58% and price elasticity of net revenue = 0.56%) allows the calculation of the net revenue elasticity of drilling activity as 1.04%.[6] That is, for every percent change in net revenue there is a 1.04 percent change in activity.

What does this imply for a potential change in royalties? The change in net revenue for a change in royalty is 1 minus the corporate income tax rate or, in the present case, 0.70. A

[4] While it has been shown that costs have a very direct relationship with prices, it is reasonable to assume that there is some time required for costs to adjust to price. The assumption in this equation is that this adjustment time is longer than one month.

[5] 56% = (100% - 20%) x (100% - 30%).

[6] 1.04 = 0.58 / 0.56

change in royalties of 1% represents a change in net revenue of 0.70%. This implies that a change in royalties of 1% will create a change in activity of about 0.73%. That is, from the current level of drilling at about 20,000 wells per year, a 1 percent change in royalties would translate into about 145 wells.

Conclusions:

Royalty changes can be expected to impact the number of wells being drilled even if the overall expected value of drilling a well remains positive on average. The nature of the geology contributes to this result - there exists a small number of large drilling targets and a very large number of small drilling targets.

As an order-of-magnitude estimate, a 1 percent change in royalties would translate into about a 150 well reduction in activity. This finding is consistent with the strong overall average well results and the marginal results for the median well. As a further observation, these wells are most likely to be shallow with correspondingly small reserves, thereby having minimal impact on annual production volumes.