

LIFTING THE HOOD ON ALBERTA'S ROYALTY REVIEW

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SUMMARY

After some delay and significant trepidation in the energy sector, the Government of Alberta has released the panel report on the structure of a new royalty regime.

While panel members, government officials and energy sector analysts understand the intricacies of the changes that have been made, there is need for an analysis that makes the changes understandable to Albertans. This report attempts to do that.

At first glance it would seem that the report calls for very little change to Alberta's royalty structure. The oil sands framework remains virtually unchanged. Existing crude oil and natural gas wells are grandfathered under the current system for 10 years. And the "modernized royalty framework" (MRF) for new wells will initially provide the same industry returns and same government take as the current system would achieve.

These similarities, however, fail to reflect important underlying changes that greatly improve the structure of Alberta's royalty framework.

Albertans will be pleased to learn that the new structure better represents the costs and revenues from oil and gas extraction. Why does this matter? Albertans, as owners of the resource, can lay claim to the resource rent: the revenue from the sale of oil and gas less all the costs to develop and produce it. By poorly reflecting costs, the old system led to distorted outcomes. It both discouraged investment in otherwise profitable projects, and overly encouraged bad ones. The new framework better targets the rent while reducing distortions and inefficient behaviour. This leads to greater value for resource owners and industry alike.

The most important feature of the MRF is its new drilling and completion cost allowance (DCCA). The DCCA essentially creates a cost formula used for every well in the province. Rather than a plethora of drilling incentive programs, the MRF offers a low royalty rate until cumulative revenues equal the DCCA. In essence, the new framework aligns with what economists view as the most efficient form of resource taxation: a revenue-minus-costs model. Importantly, the formula is based on depth and length - key drivers of costs - not the actual costs themselves. This benchmarking creates an innovation incentive for companies to affect more efficient production. Over time, lower costs mean larger resource rents. This gets returned to Albertans as the DCCA for future wells is adjusted annually based on a cost index of all wells recently drilled in the province. Using a calculated benchmark as opposed to actual costs also eases the administrative burden that would otherwise be required for complex and costly monitoring.

For oil sands, transparency is the focus. The rates and structure of royalties remain the same, as the royalty framework already uses the efficient revenue-minus-costs model. To ensure Albertans have the confidence in the process, the panel proposed that all oil sands projects annually publish information on bitumen production, revenues, operating and capital costs, and royalties paid. The report also includes a recommendation for streamlining cost-dispute resolutions.

By focusing on the structure, as opposed to the split, the panel's report takes seriously the economic theory of efficient resource taxation. The panel's recommendations are focused on increasing the size of the pie, not haggling over how a small pie gets divided.

INTRODUCTION

At long last, the much-anticipated Alberta royalty review has been made public.¹ After all the consternation and hand wringing by pundits of all stripes, what has the panel produced?

The short answer is:

- The oil sands framework has been left essentially unchanged, but for greater levels of transparency on allowable costs;
- Existing crude oil, natural gas liquids and natural gas wells remain on the current system for the next 10 years;
- For new wells drilled on or after Jan. 1, 2017, the panel has proposed what it is calling the *modernized royalty framework*, calibrated to initially deliver the same industry returns and government take as would have been achieved under the current system.

To many, all this may seem like nothing has changed. Some might be tempted to compare it to bringing your car in for a tune-up, only to have it remain there for months, and when it is returned to you, it looks and smells like the same old car you brought in long ago. But, just like the car, the panel's report requires looking under the hood to find the real changes.

This paper examines the details of the panel's recommended changes to the royalty framework. It explains how the proposed system works, how it differs from the current one, and assesses the recommended changes relative to what economic theory tells us about efficient resource taxation.

How did we get here?

In May 2015, Alberta elected a new governing party for the first time in over 40 years. The NDP was elected with a platform that included a call to review Alberta's royalty framework. In late June, the royalty review was officially launched with Dave Mowat, president and CEO of ATB Financial, selected to chair the panel. In late August, the remaining three panel members were announced: Leona Hanson, mayor of the town of Beaverlodge, AB; Peter Tertzakian, chief energy economist and managing director at ARC Financial; and Annette Trimbee, former Alberta deputy minister of finance and current president of the University of Winnipeg.

The panel's stated mandate was "*to assess whether the royalty framework is designed so that it will, now and in the future, meet four related objectives:*

1. *Provide optimal returns to Albertans as owners of the resource;*
2. *Continue to encourage industry investment;*
3. *Encourage diversification opportunities such as value-added processing, innovation or other forms of investment in Alberta; and*
4. *Support responsible development of the resource.*"²

¹ The Royalty Review Panel's report can be found at: <http://www.alberta.ca/documents/royalty-framework-report.pdf>.

² Government of Alberta, *Alberta's Royalty Review 2015*, <http://www.energy.alberta.ca/Org/pdfs/RRmandate.pdf>.

To achieve its mandate, the panel undertook two processes. First, there was a public engagement process, which involved listening to and gathering feedback from stakeholders across Alberta representing a broad spectrum of perspectives. The second process was a technical review involving expert working groups and energy consultants to dig deeper on the specifics of the royalty framework.

Almost exactly five months after the full panel was formed, we have the result of its work. The four recommendations made by the panel are enumerated in the executive summary:

- #1 Establish guiding principles and design criteria for Alberta's royalty framework;
- #2 Modernize Alberta's framework for crude oil, liquids and natural gas;
- #3 Enhance royalty processes for the oil sands; and
- #4 Seize opportunities to enhance value-added processing.

This paper focuses exclusively on the proposed changes to the royalty framework in recommendations #2 and #3. Sections 2 and 3 of this paper attempt to get past the headlines, outlining the specifics of all the mechanisms involved and how they differ from the current royalty framework, and assessing the changes based on the principles of efficient resource taxation.

But before we dig into the details of the changes, Section 1 begins by exploring the contentious topic of fair share, highlighting the irrelevance of royalty rates by themselves in that discussion.

SECTION 1 - RATES, SHARES AND VALUE

Many will look to the panel's report to answer the question of whether rates are going up or down. But despite the interest, what happens to the royalty rate on gross revenues, in itself, is not the relevant question. What Albertans, as owners, should be concerned with is not the percentage of revenue they receive; Albertans should be focused on what share of the resource rent they receive, and – just as importantly – how much total rent is achieved.³

To emphasize this point, the following example illustrates how the royalty rate applied to gross revenue relates to the share of rent. In the following two tables, the rows represent various scenarios where the price has changed (Column A). For simplicity, cost (B) is left the same, and taking some liberty with the precise definition, rent per unit of output (C) is calculated as price minus cost. The royalty rate (D) is applied to revenue, or price in our per-barrel example, to determine the amount of royalty collected (E). Finally, the share of rent (F) is calculated as the royalty collected divided by the rent.

³ The resource rent is defined as the excess return from an economic activity over and above all of the costs of undertaking the activity, including the opportunity cost of the capital investment required. In other words, it is what is left over from the sale of a resource (i.e. the revenue) after subtracting all the costs to explore, develop, produce and deliver the resource, including a risk-adjusted return on capital. A more thorough discussion of rents can be found in the Appendix of this paper.

For a numerical example, take the first row of Table 1. The price of \$60 less the cost of \$35 equals the \$25 rent. To achieve a 67 per cent share of this rent, a 28 per cent gross royalty rate must be applied (28 per cent x 60 = \$17; \$17/\$25 = 67 per cent).

To achieve a constant share of rents, Table 1 demonstrates how royalty rates must adjust with price. With lower prices, a lower royalty rate achieves the same share as a higher rate at high prices.

TABLE 1 ILLUSTRATIVE EXAMPLE WITH FIXED SHARE OF RENTS PER BARREL

(A)	(B)	(C)	(D)	(E)	(F)
Price	Cost	Rent	Royalty Rate	Royalty collected (D x A)	Share of Rent (E / C)
60	35	25	28%	17	67%
50	35	15	20%	10	67%
40	35	5	8%	3	67%

Illustrative values in \$/barrel.

Another way to look at this is by asking: What share of rents is achieved with a fixed royalty rate?

Table 2 shows how a fixed royalty rate can result in markedly different shares of the rent collected; the share of rent increases as price declines. In fact, in this example, at low prices, and consequently low rents, the share of rent surpasses 100 per cent.⁴ With fixed royalty rates, the highest share of rent is achieved when the rent and total royalty collected are the smallest, while the lowest share is achieved when rents are the highest.

TABLE 2 ILLUSTRATIVE EXAMPLE WITH FIXED ROYALTY RATES PER BARREL

(A)	(B)	(C)	(D)	(E)	(F)
Price	Cost	Rent	Royalty Rate	Royalty collected (D x A)	Share of Rent (E / C)
60	35	25	25%	15	60%
50	35	15	25%	12.5	83%
40	35	5	25%	10	N/A*

Illustrative values in \$/barrel.

* The share of rent would be N/A as firms would shut in production, resulting in zero rents and zero royalties.

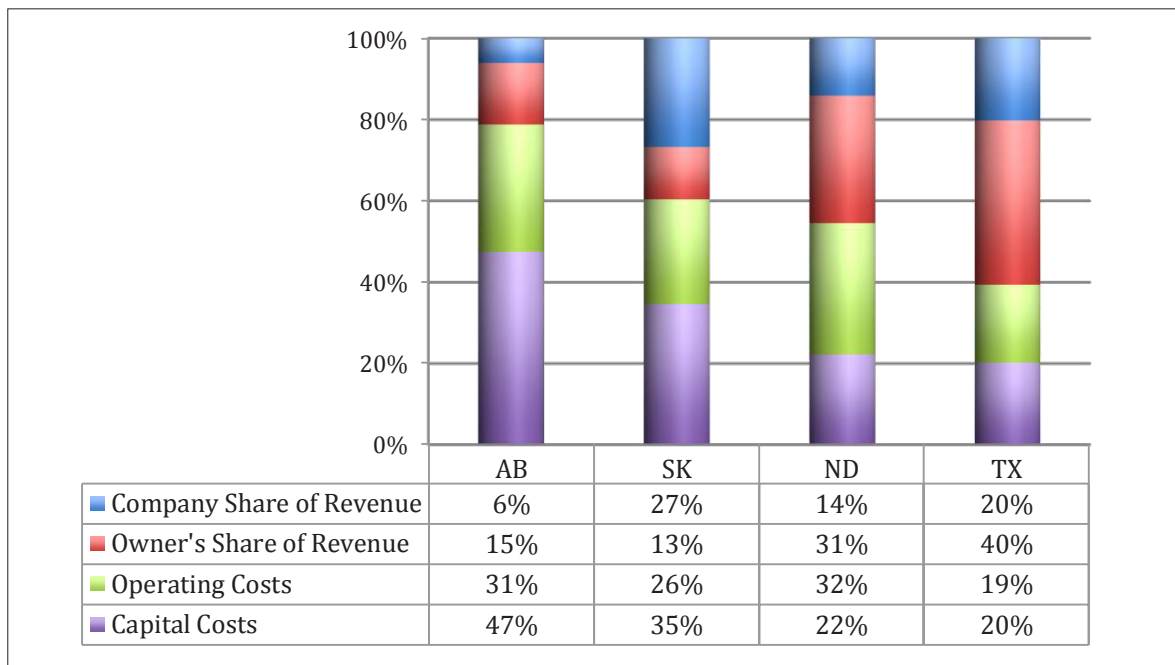
These examples reinforce the need to look at both the share as well as the total amount of the rents. Receiving a large share only because the rent itself is small is not an optimal outcome for Albertans. To ensure that firms retain an interest in maximizing the total amount of rent, their incentives must be aligned with that goal. The cost of alignment is that the resource owner must share some of the rent.

⁴ In this case, firms would no longer be operating profitably – resulting in no production and no royalties.

How do we compare to other energy-producing jurisdictions?

For the purposes of the review, the Department of Energy hired Wood Mackenzie, a consultancy, to provide comparative analysis of Alberta’s fiscal take from oil and gas development as compared to its energy-producing peers.⁵ An apples-to-apples comparison is difficult, as one must control for the quality or type of oil and gas resources, the full range of taxes and fees the owner collects (e.g. corporate and municipal taxes and tax structures, access fees, environmental levies, etc.), as well as political, regulatory and safety risks that are challenging to quantify. It is also worth noting that looking at a single resource in Alberta and comparing it to another region is not fully representative of how Alberta compares more broadly. All this is to say: Take the comparative analysis with a grain of salt. That being said, below is the split of a barrel for a highly economic well in Alberta versus comparable resources in Saskatchewan, North Dakota and Texas.⁶ The split of a barrel refers to how the revenue from the sale of a barrel of oil is apportioned to operating costs, capital costs, company share of revenue and owner’s share of revenue.

FIGURE 1 SHARES OF REVENUE FROM A \$60 BARREL OF OIL ACROSS JURISDICTIONS



Source Data: Panel Report, Wood Mackenzie Data Appendix, p. 28. Source data do not sum precisely to 100 per cent.

Things to note from Figure 1:

- Alberta’s costs are a much greater component of the barrel;
- Alberta’s industry margins are slim;
- Owner’s share of revenue is similar in Alberta and Saskatchewan;
- Texas has the highest owner’s share and lowest costs per barrel.⁷

⁵ The full details of the Wood Mackenzie analysis are available in the panel report.

⁶ Specifically, the Alberta play modelled is a Cardium Pembina West type-well.

⁷ In Texas and North Dakota, the owner’s share includes payments made to private landowners who hold the mineral rights, not just the government. In these jurisdictions, privately held mineral rights are more common than in Canada.

A different story appears when the data are presented as owner’s share of rent. With the Wood Mackenzie data, we can approximate the rent as the portion of revenue remaining after costs (i.e. owner’s share of revenue plus company share of revenue in Figure 1).⁸ Thus, we can calculate:

$$\text{Owner's Share of Rent} = \frac{\text{Owner's Share of Revenue}}{\text{Owner's Share of Revenue} + \text{Company's Share of Revenue}}$$

TABLE 3 OWNER’S SHARE OF RENT

	Alberta	Saskatchewan	North Dakota	Texas
\$60 Oil	71%	33%	69%	67%
\$100 Oil	61%	30%	62%	62%

Source Data: Panel Report, Wood Mackenzie Data Appendix, pp. 28-29.

Table 3 appears to put Alberta at a comparable level to North Dakota and Texas in terms of owner’s share of rent. At \$60 oil, Alberta receives 71 per cent of the available rent, as compared to 69 per cent and 67 per cent for North Dakota and Texas. At \$100, Alberta receives 61 per cent, as compared to 62 per cent for both North Dakota and Texas. Notably, Saskatchewan appears an outlier, receiving a third or less of the available rent.

All of this is to say that Alberta is taking a comparable share of the rent, but importantly, Alberta’s total available rent is small due to high costs. Thus, in the recommendations that follow, the emphasis is on improving the royalty framework’s structure to incentivize innovation and cost competitiveness, rather than focusing on the split.

SECTION 2 - CRUDE OIL, LIQUIDS AND NATURAL GAS RECOMMENDATIONS

This section outlines the changes to the crude oil, liquids and natural gas frameworks, breaking down the details of the panel’s proposed “*modernized royalty framework*” (henceforth MRF), how it works and how it differs from the current system, and an assessment of the changes vis-à-vis what economic theory tells us about efficient resource taxation.

First, all the recommended changes apply to new wells only. Wells drilled prior to the implementation of the MRF will remain on the current system for a period of 10 years, after which all wells will be transferred to the MRF. The MRF applies only to new wells drilled on or after Jan. 1, 2017.

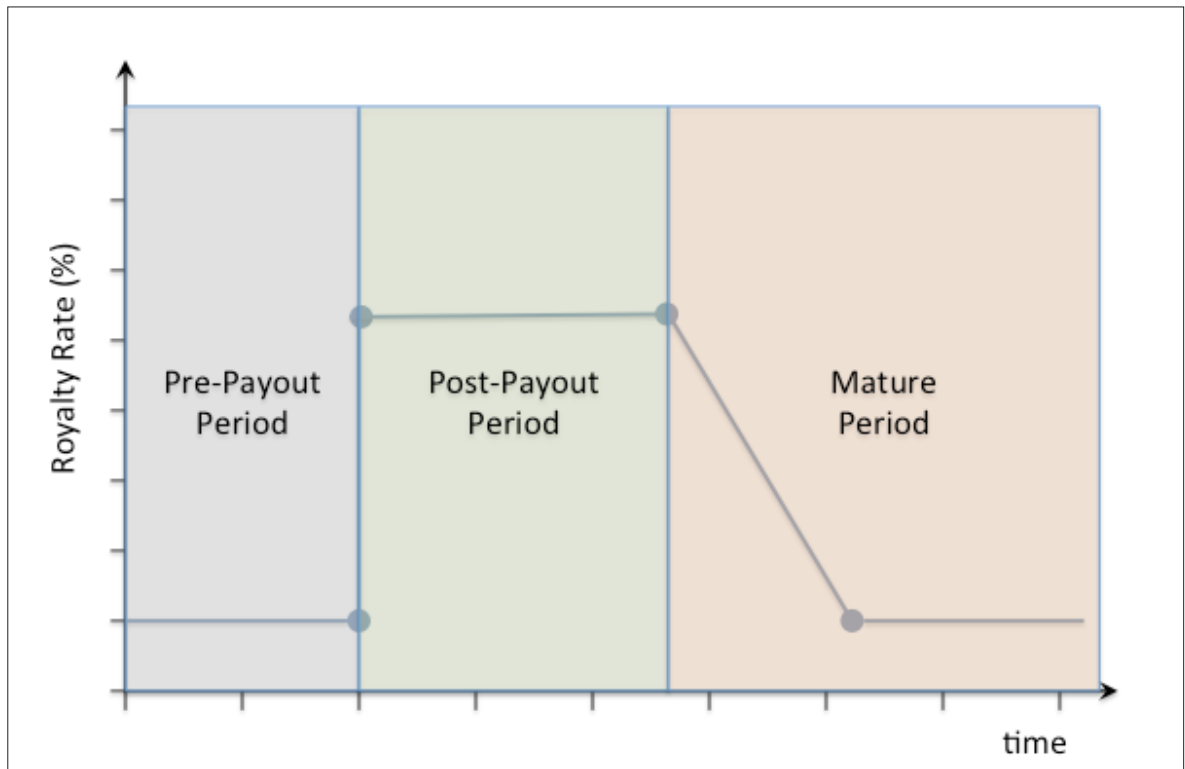
Let’s begin with the big picture of how the MRF works.

⁸ Precisely speaking, this is net revenues and not rent. But for comparative purposes across jurisdictions with similar risk profiles, one can use these terms similarly.

At first glance, the MRF will appear similar to the current system (see Figure 2):

1. A pre-payout period during which producers are charged a low royalty rate until cumulative revenues reach some notion of the upfront costs (i.e. payout is achieved);
2. A post-payout period whereby the royalty rate jumps to a higher rate that varies with commodity price;
3. A mature or low-production period where the rate declines to a floor level.

FIGURE 2 SCHEMATIC OF A GENERIC ROYALTY SYSTEM



Intuitively, the pre- and post-payout structure reflects the partnership that exists between producer and resource owner. Initially, when the producer is still recouping its upfront costs, the resource owner charges very little in the way of royalties.⁹ Once the producer has recouped its investment (i.e. payout has been achieved), a larger royalty rate is applied. Finally, in the mature phase of a project, when operating costs per barrel reduce cash flow, the royalty rate is again reduced.

While the current system may appear to match the above description, looking more closely we see that the structure and triggers that define the pre- and post-payout periods are imprecise. In the MRF, these triggers have been completely revised. Let's look at each separately, comparing the current system with the MRF.

⁹ In a true cash flow tax, the pre-payout period royalty would actually be negative. That is, the government would be crediting the company while its cash flow is negative, and recouping more during the positive cash flow post-payout period.

2.1 Pre-Payout Period

Under the current system, the notion of pre-payout does not technically exist. What exists is a plethora of drilling incentive programs that have the effect of lowering royalties during the initial life of a well, based on time, volume and depth parameters, and combinations thereof (see Table 4). Rather than an attempt to approximate costs, these programs are more akin to discounts. They provide incentives for investment in an untargeted, and inefficient, manner.

TABLE 4 LIST OF CURRENT DRILLING INCENTIVE PROGRAMS

Program	Brief Description	Key Variables
New Well Royalty Rate (NWRR) ^a	5% rate for first 12 months of production	Time-based.
Shale Gas New Well Royalty Rate (SGNWRR) ^b	5% rate for first 36 months of production For wells designated as shale gas; Supplants NWRR	Time-based. Fluid-code eligibility.
Horizontal Oil New Well Royalty Rate (HONWRR) ^c	Lower rates on the first 50,000 barrels of oil or 18 months. Volume and time caps increase with measured depth. At measured depths > 4,500mw, the volume and time caps increase to 100,000 barrels and 48 months. Supplants NWRR.	Volume- and time-based. Volume and time caps are a function of depth. Well-type eligibility.
Horizontal Gas New Well Royalty Rate (HGNWRR) ^d	Lower rates on the first 500 MMcf of gas or 18 months. Not depth sensitive. Supplants NWRR.	Volume- and time-based. Well-type eligibility.
Natural Gas Deep Drilling Program (NGDDP) ^e	Royalty credit applicable only to gas wells greater than 2,000m vertical depth. Credit increases with measured depth. For development wells, the initial credit is \$625 per metre up to 3,500m of measured depth, increasing to \$2,500 per metre for all measured depth greater than 3,500m, and \$3,000 per metre at measured depths greater than 5,000m. Values are slightly different for exploratory wells. The royalty credit is capped at \$8 million with a 60-month expiry. NGDDP overlaps Horizontal Gas NWRR, in that the 5% rate will apply first, with NGDDP applied after the expiration of the 5% rate. However, the 60-month time cap on the NGDDP begins when the well is drilled, not at expiry of the NWRR.	Measured depth-based. Vertical depth-eligibility. \$ and time-capped. Overlaps with HGNWRR.

^a Alberta Energy, *New Well Royalty Rate FAQ*, http://www.energy.alberta.ca/About_Us/1854.asp

^b Alberta Energy, *Shale Gas NWRR FAQ*, http://www.energy.alberta.ca/About_Us/1860.asp

^c Alberta Energy, *Horizontal Oil NWRR FAQ*, http://www.energy.alberta.ca/About_Us/1862.asp

^d Alberta Energy, *Horizontal Gas NWRR FAQ*, http://www.energy.alberta.ca/About_Us/1864.asp

^e Alberta Energy, *NGDDP FAQ*, http://www.energy.alberta.ca/About_Us/1856.asp

All of these programs share something in common: They do a poor job of reflecting costs. To get at the rent, we need to accurately reflect costs. For example, the Horizontal Oil New Well program offers lower royalties on the first 50,000 barrels of production. But this results in a lower royalty rate on \$1.5 million of revenue when oil prices are \$30, and on \$5 million of revenue when prices are \$100. The value companies receive from the drilling programs is low in low-priced times (when they likely need it most), whereas in times of high prices, the value is high.

Introduction of a drilling and completion cost allowance

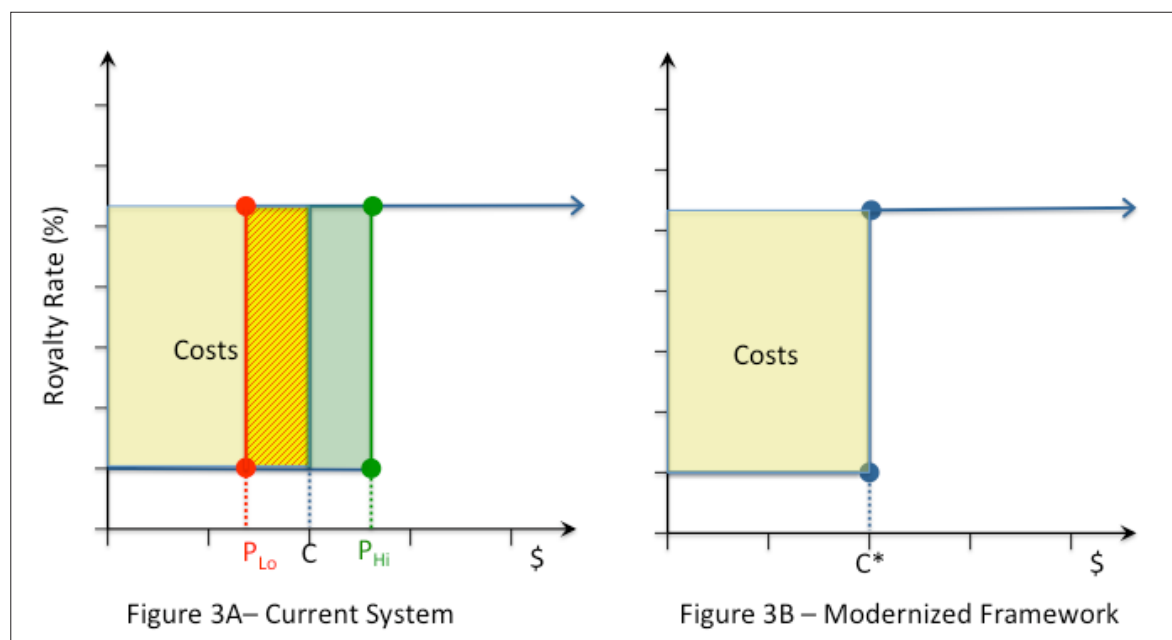
The MRF replaces all the current drilling programs with what is being called a drilling and completion cost allowance (henceforth DCCA) whose goal is to reflect drilling and

completion costs.¹⁰ The DCCA determines the trigger point whereby the royalty framework shifts from pre- to post-payout. This shift occurs when cumulative revenues equal the DCCA (point C^* in Figure 3B). The main benefit of the DCCA is that by more accurately reflecting costs the royalty framework is better targeting the true rents of the well.

Why does “more accurately reflecting costs” matter?

Consider a well, facing either low or high prices, under the current system versus the MRF. The cost to drill the well is represented by C (Figure 3A). Let us assume that at some measure of “normal” prices, the existing programs reflect the actual drilling costs of a well. Thus, at low prices, the existing programs do not sufficiently reflect the producer’s cost (red/yellow hashed area, Figure 3A). As a result, the royalties represent too large a share of the rent, potentially creating a situation where the company chooses not to invest in an otherwise profitable project. Conversely, at high prices, the existing programs are overly generous (green area, Figure 3A), boosting industry returns and creating a situation where the royalty framework is under-collecting the resource owner’s share.

FIGURE 3 COMPARISON OF CURRENT SYSTEM AND MRF PRE-PAYOUT PERIOD



Under the MRF, the DCCA is measured in dollars without a time or volume cap (represented by C^* , Figure 3B). Thus, the MRF applies the same payout trigger regardless of prevailing commodity prices. In the MRF, the trigger to move to the post-payout period

¹⁰ The drilling and completion cost allowance only reflects the capital costs of drilling and completion at the early stage of a well. These are the bulk of capital costs in most cases. The remaining capital costs and operating costs do not receive a separate allowance. Estimates of both, however, will be taken into account via the calibration of the post-payout royalty rate.

is when cumulative revenues equal the DCCA.¹¹ The benefits of this new method are twofold:

1. It reduces companies' risk of a mismatch between the actual costs of a project and the cost recognition provided by the royalty framework. This means their expected returns more closely align with their actual returns, all else equal. By reducing risk, companies are provided more certainty, allowing them to reduce the additional return required to accept the prior risk (i.e. the risk premium). Reducing this risk premium provides more value for the resource owner;
2. In low-price periods, the current programs may not sufficiently reflect costs. This has the potential to distort investment decisions by discouraging projects that would otherwise be profitable. The MRF removes this distortion, encouraging all profitable investments.

In addition to its simplicity and improved cost accuracy, another benefit of replacing the current drilling programs with the DCCA is that it reduces inefficient activity that occurs only as a result of the programs. For example, the new well royalty rate offers a lower royalty rate over the first 12 months of production; thus, companies have an added motivation to capture a greater amount of revenues in the early life of their wells while they face the lower rate. This means that companies may not follow the time path of production that maximizes the total return from the resource (i.e. the rent), but rather the one that maximizes their private returns. An efficient royalty system should align those two goals.¹²

Another example of a current distortion is found in the natural gas deep drilling program (NGDDP). The NGDDP only applies to wells deeper than 2,000 metres. This distorts the decision to drill at depths slightly below this level. If a company can drill a 1,950m well and receive X in profit, or go 50m deeper and earn a little less in pre-tax profit, it may still be worth it due to the credits associated with the NGDDP. An ideal royalty framework should produce the same investment and activity behaviour both with and without the framework. While "ideal" is not always feasible, replacing the current programs with the DCCA removes many of these distortions.

How will the drilling and completion cost allowance be determined?

The DCCA will be different for every individual well in the province based on its observable characteristics, not its actual costs. This is important. By basing the DCCA on observable metrics, it creates a "beat the bar" incentive. Companies that innovate and drive down their costs will fully appropriate the gains from cost reduction. It also removes the administrative burden of having to monitor costs across hundreds of thousands of wells.

¹¹ Note: This isn't full payout in the sense that revenues do not also cover royalties and operating costs during the pre-payout period. A true payout would be when cumulative revenues equal DCCA plus royalties paid and a measure of operating costs. This is instead reflected in the calibration of the post-payout royalty rate. Had these costs been included in the trigger, the post-payout royalty rate would have to be set at a higher level. Instead, the post-payout royalty rate must be set taking into account expectations of operating costs.

¹² In parts of Texas and North Dakota, for example, firms are currently experimenting with choke-back technology that slows production declines. This has the potential to offer a greater total yield, albeit over a longer period of time. The current time-based programs discourage this activity. See, for example, <http://www.bloomberg.com/news/articles/2015-10-01/oil-drillers-bet-choking-wells-will-keep-shale-from-going-bust>

Appendix E in the panel’s report details how the DCCA will be determined.¹³ The panel is proposing a formula that calculates the DCCA as a function of vertical depth and lateral length:

where:

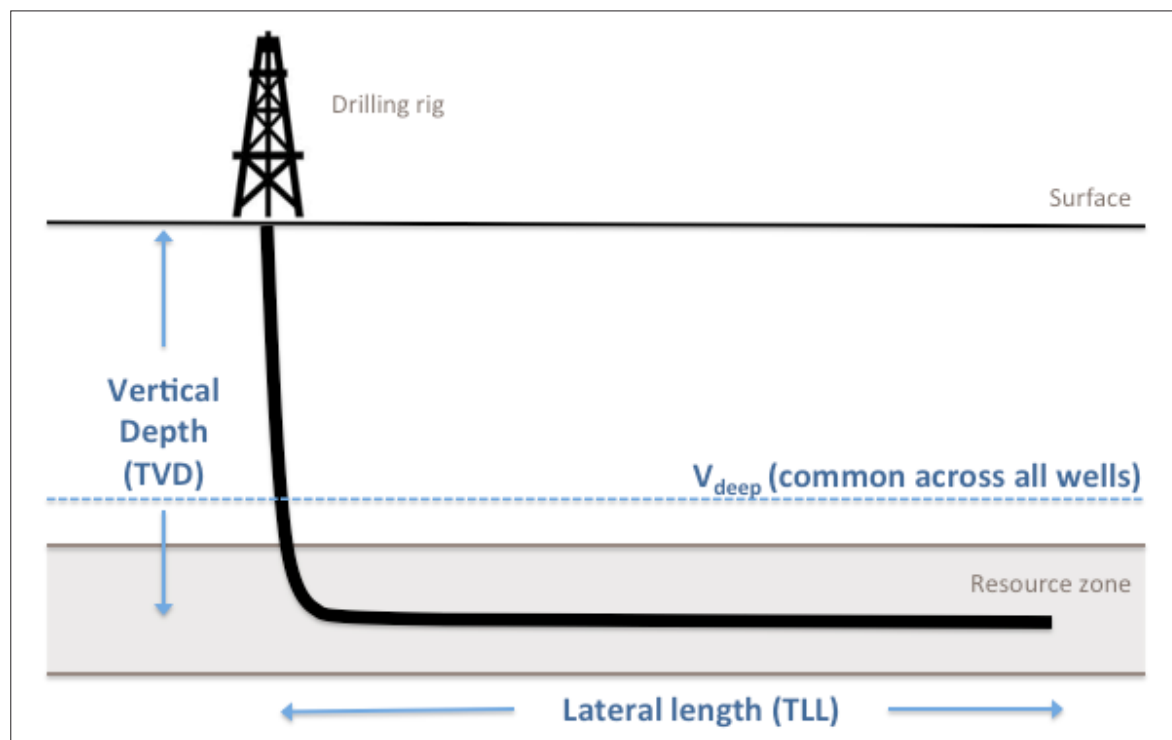
$$DCA = a_1TVD + a_2(TVD - V_{deep}) + a_3(TVD * TLL)$$

TVD is the true vertical depth;

TLL is the total lateral length, calculated as total measured depth (i.e. length) minus *TVD*;

V_{deep} is a vertical depth trigger that is the same for all wells, below which the drilling cost is recognized to be greater per metre.

FIGURE 4 ILLUSTRATION OF DEPTH AND LENGTH PARAMETERS OF A TYPICAL WELL



The coefficients (a_1 , a_2 , a_3) of the formula will be estimated by performing a statistical analysis of the correlations between actual province-wide drilling and completion costs and the above depth and length characteristics. The intuition behind the relationship is:

a_1 recognizes that costs increase for every metre drilled vertically;

a_2 recognizes that these costs per vertical metre are greater as the well gets deeper;

a_3 recognizes that the cost to drill laterally is greater the more vertically deep a well is.

¹³ The precise determination of the DCCA will be done by a calibration team, led by Alberta Energy. The panel recommends that publication of the final DCCA formula be completed by March 31, 2016. Panel Report, p. 84.

A capital cost index (yet to be developed) of all wells drilled in Alberta in recent years will scale the DCCA annually to reflect changes in capital costs over time. The panel recommends that the government hire energy consultants and reservoir engineers to facilitate its construction and maintain it over time. The index will initially be set at 100, with future year DCCA calculations being scaled by the new capital cost index divided by 100.¹⁴ Once a well is drilled, its DCCA is fixed; the scaling only applies to new wells in subsequent years.

The time period over which the capital cost index is to be calculated is not defined in the panel's report. Using only one year of cost history creates the potential for large swings in the DCCA. This is mitigated somewhat by an annual +/- five per cent maximum change. Calculating the capital cost index based on a longer period (e.g. a rolling three-year period) would provide a trade-off between accuracy of costs and volatility of the allowances.

2.2 Post-Payout Period

In the current system, once the drilling incentive programs are exhausted, the royalty rates jump to a rate that is a function of (i) price, (ii) production, and in the case of natural gas, (iii) well depth. The current system has a range of post-payout royalty rates between zero to 40 per cent for oil, and five to 36 per cent for gas.^{15, 16}

The formulas are complex, but in essence:

- Rates increase with price;
- Rates decrease as production declines;
- Greater measured depth results in lower rates for gas.

The MRF simplifies these formulas in two ways. First, the post-payout rate will now only be a function of price. Production and depth variables are eliminated.¹⁷ This simplifies the royalty framework. In keeping with the intuition behind targeting the rent, the higher costs of greater depth are acknowledged in the drilling and completion cost allowance, not the post-payout rate. This implicitly assumes that depth-driven differences in operating costs are less material than the benefit of simplicity.

Second, the MRF formula applies uniformly across all hydrocarbons. The current system has different formulas for crude oil, liquids and natural gas. Notably, unlike crude oil and natural gas, the natural gas liquids formulas are not a function of price or production – they are flat rates. This creates an abrupt difference in applicable royalty rates if a well is deemed to produce crude oil, or a natural gas liquid. Depending on the classification, a company can be exposed to a significant royalty cost shock due to the production of an

¹⁴ The capital cost index is to be published by May 31 prior to the relevant year to allow sufficient time for industry investment planning decisions.

¹⁵ Alberta Energy, *Alberta Royalty Framework formulas Oil*, <http://www.energy.alberta.ca/Org/pdfs/OILFormulas2010.pdf>.

¹⁶ Alberta Energy, *Alberta Royalty Framework formulas Natural Gas*, <http://www.energy.alberta.ca/Org/pdfs/GASFormulas2010.pdf>.

¹⁷ Note: Production still plays a role in that it triggers when the well moves to the mature period. Discussed in Section 2.3.

unintended hydrocarbon.¹⁸ This risk may result in companies avoiding drilling in some sections of their land, despite potential value.

The proposed system merges all the frameworks. Rates as a function of price apply across all hydrocarbons. Rather than an abrupt switch from one classification to another, the new system calculates a blended rate based on the production weights of a well (basically, weighted by the percentage of each type of hydrocarbon produced from a well). This ensures that the result of drilling an unintended hydrocarbon is felt only on that additional amount, rather than changing royalties paid on the entire production of the well. The risk of a significant change in royalty costs is now removed. Again, lower risk to companies means less risk premium required and more value for the resource owners.

How will the post-payout royalty rate be determined?

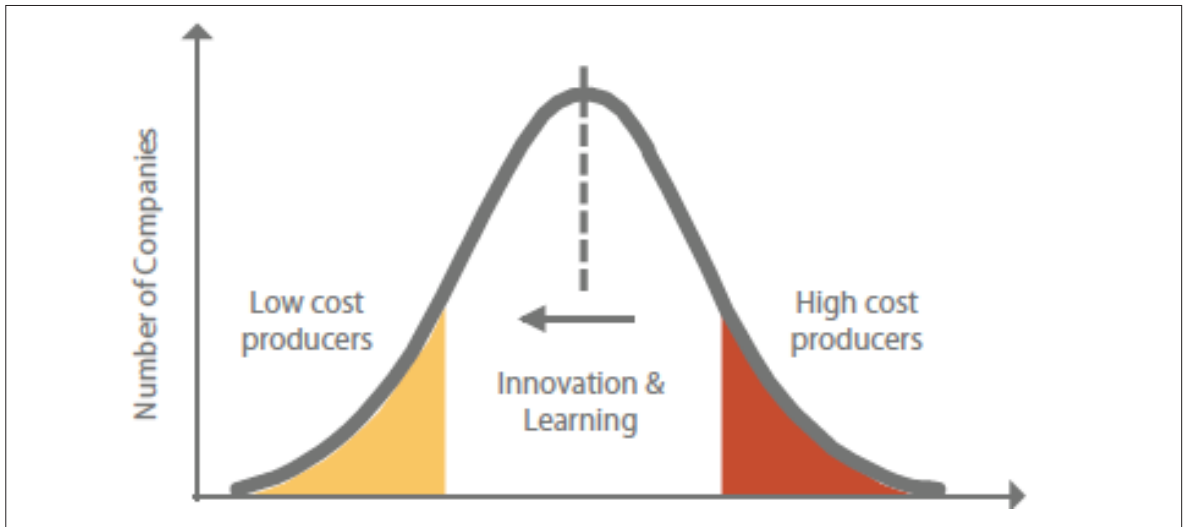
The post-payout royalty rates are not included in the panel's report. There is a directive, however, to "*calibrate the combination of Drilling and Completion Cost Allowance and new post-payout royalty rates to target the industry returns and Albertans' share of value that are achieved under the current regime, taking into account that current drilling programs are not well designed for very high and very low prices.*"¹⁹

What this means is that the height of the jump in rates we observe in Figure 2 going from pre- to post-payout will be set with the goal of maintaining the current split of rent. Precise details on the rates will require publication of the final formulas, which the panel recommends be completed and published by March 31, 2016. This exercise will, of course, only be able to match returns on average, and thus there will be winners and losers across different types of wells, and across different companies, relative to the current royalty regime. However, despite some exceptions due to geology and other extenuating circumstances, the distribution of winners and losers should be representative of the cost-competitiveness and efficiency attributes of the companies. En masse, those on the winning side should be those companies who are capable of drilling similar wells at lower cost.

¹⁸ The product classification also determines which current drilling program is applicable to a well. This creates potentially an even larger distortion. The DCCA proposed in the MRF is independent of hydrocarbon type.

¹⁹ Royalty Review Panel Report, p. 10.

FIGURE 5 ILLUSTRATIVE DISTRIBUTION OF COSTS



Source: Royalty Review Panel Report, p. 41

If a company is consistently on the wrong side of the above cost distribution (Figure 5), it stands to earn lower returns than the innovators on the left side. Over time, either these companies will have to improve processes to reduce their costs, or they will remain at a competitive disadvantage. Eventually, knowledge transfer or acquisitions should drive companies to shift to the left, creating more value for the resource.

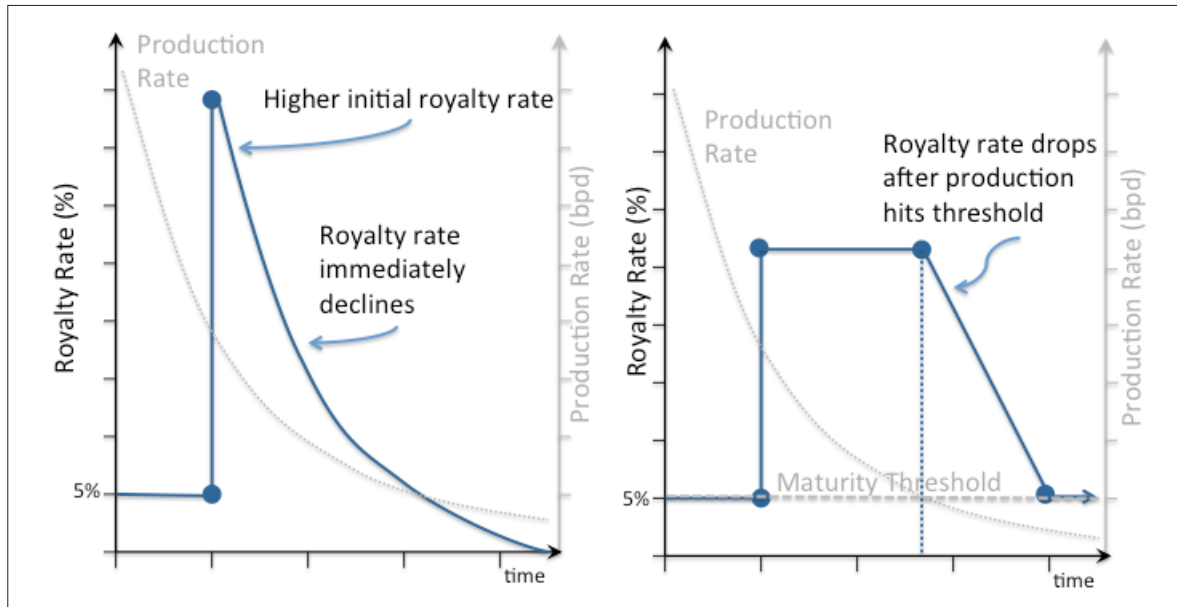
2.3 Mature Period

Under the current system, there is no abrupt cutoff into mature status. Instead, the post-payout royalty rate is a function of production from the moment the drilling incentive programs expire (Figure 6A). As production declines, so too does the rate. In the case of oil, at very low production levels (and at low prices), this can drive the rate to zero per cent. The key here is that the rate is being adjusted throughout the life of the well.

In the MRF, production levels do not enter into the formula until the well's productivity reaches a specific threshold. The panel's report is suggesting this maturity threshold be set in the area of 20 barrels per day (oil) and 200,000 cubic feet per day (gas).²⁰ After this point, the royalty rate declines to a new minimum royalty rate of five per cent (Figure 6B).

²⁰ Royalty Review Panel Report, p. 86.

FIGURE 6 ROYALTY RATES AND PRODUCTION RATES



The first question to be raised is why royalty rates should be a function of production rates at all. Again, this goes back to rents. If we accept that a portion of operating costs are fixed, then at lower levels of production the cost per barrel to produce oil is higher. To reflect these higher operating costs, production rates are used as a proxy.

The current system is generally better aligned with operating costs, since the royalty rate adjusts throughout the life of a well, not just after the maturity threshold is reached.

However, given that decisions to cease production (i.e. shut in) more commonly occur in the mature phase of the well (where costs per barrel are highest), the MRF's lack of alignment with operating costs during the early phase of the post-payout period is unlikely to produce distortions. In other words, where it matters – at very low production rates in maturity – the MRF reduces the royalty rate to reflect the higher per barrel operating costs. This raises a trade-off between the current system's alignment with costs and the simplicity of the MRF.

One feature in the MRF that may potentially lead to a change in behaviour is the introduction of a minimum royalty rate of five per cent. Mature wells on the cusp of becoming no longer profitable may alter their shut-in decision on account of the requirement for five per cent gross royalties (as compared to the current zero per cent floor for oil). As the MRF only applies to new wells, this effect is unlikely to be observed for at least the next 10 years.

SECTION 3 - OIL SANDS RECOMMENDATIONS

On the matter of oil sands royalties, the panel recommended leaving the structure and rates unchanged. The oil sands royalty framework already employs a pre- and post-payout

system, with a rate applied to net revenues in the latter period. This comes very close to targeting the rent, and is recognized as an efficient way to tax resources.²¹

Background Material

For a thorough yet accessible description of the oil sands framework, see The School of Public Policy, *Primer on Alberta's Oil Sands Royalties*, by Dr. Sarah Dobson.

<http://policyschool.ucalgary.ca/sites/default/files/research/ab-oil-sands-royalties-dobson.pdf>

Instead, the panel focused its recommendations on improving the transparency of allowable costs and pricing that enter into the net revenue calculation. Specifically, this requires all oil sands projects to publish an annual summary that includes financial information on bitumen production, revenues, operating costs, capital costs and royalties paid.

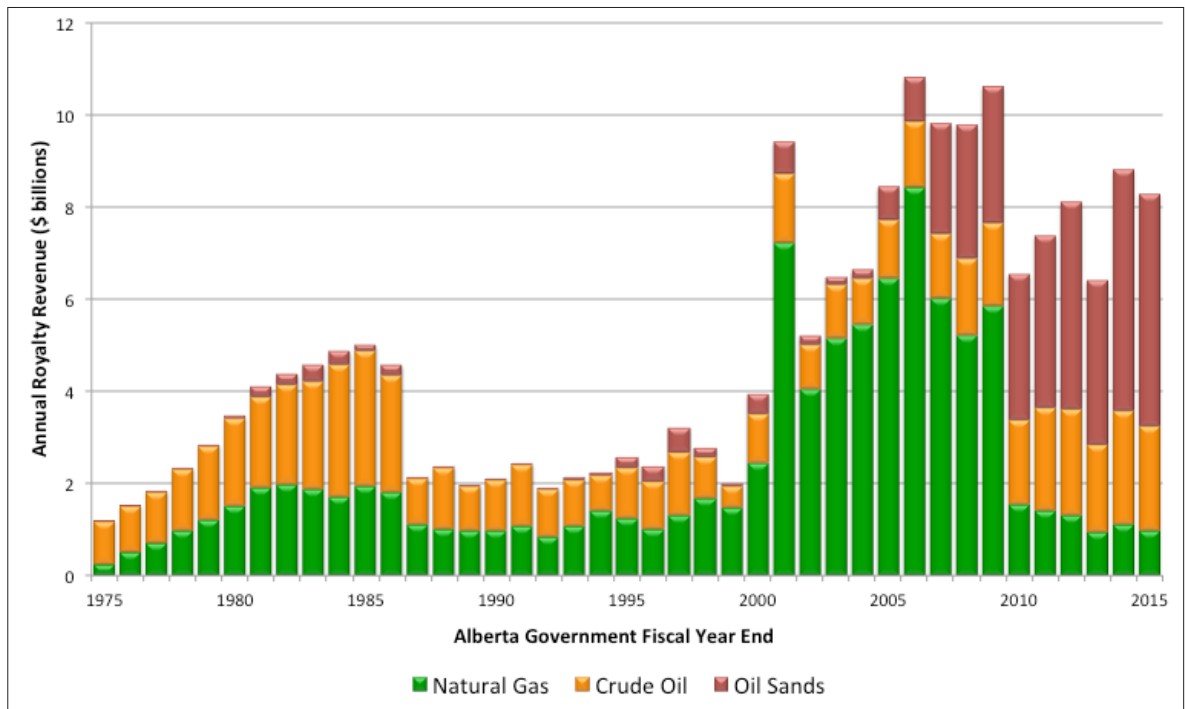
In addition, the panel is recommending that the cost dispute resolution process be improved so that lingering cost disputes are a thing of the past. This includes the ability to issue advanced rulings, the authority to render prompt decisions, and be staffed by experts on oil sands operations.

More cost transparency and an improved dispute resolution process are laudable goals. To be an effective cash flow tax system, allowable costs must be reasonable and appropriate to ensure the base of taxation is indeed the resource rent.

The panel clearly recognized the relative importance of oil sands revenues to Alberta's total resource revenue. As recently as 2009, natural gas provided the bulk of the province's royalty revenue (Figure 7). However, with the collapse in natural gas prices, that changed. Oil prices rebounded from their lows of 2009, and coupled with the significant growth in oil sands production, led oil sands royalty revenue to offset much of the drop in natural gas revenue. For fiscal 2015/16, Albertans can't expect any such luck.

²¹ See, for example, Mintz, J. and Chen, D., "Capturing Economic Rents from Resources through Royalties and Taxes," *School of Public Policy Research Papers*, Vol. 5, Issue 30, October 2012.

FIGURE 7 ALBERTA'S ROYALTY REVENUE BY PRODUCT STREAM



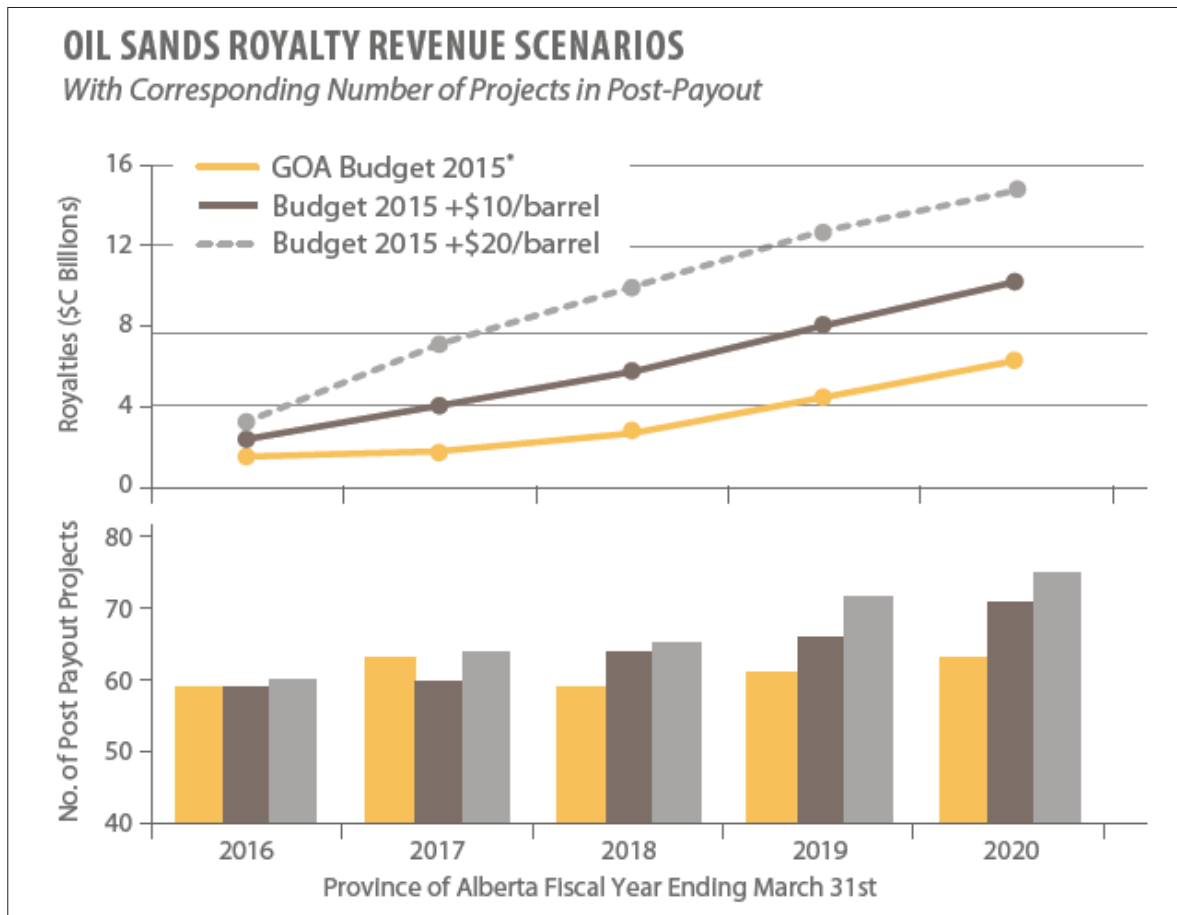
Source Data: Alberta Energy, *Alberta Resource Revenues: 1970 to Present*, http://www.energy.alberta.ca/About_Us/2564.asp

On a more optimistic note, the future looks brighter. Due to the progression of oil sands projects from pre- to post-payout, and the commensurate increase in royalty collection, Albertans stand to receive a significant increase in oil sands royalty revenue, even at current forecasted prices.²² In many ways, the oil sands that have been in pre-payout are, to Albertans, like an investment in a bond about to pay out for decades. Figure 8 shows that at current forecasted prices, oil sands royalty revenue in 2020 is projected at \$6.5 billion. That would return total royalty revenues to 2014 levels, when WTI prices averaged \$96 US/bbl.

More striking is what a \$10 or \$20 increase to oil prices does to provincial revenue. A \$10 increase in prices puts oil sands royalty revenue at \$10.5 billion. A \$20 increase from current forecast prices results in nearly \$15 billion of oil sands royalty revenue. Hope is not a strategy, but Albertans are sitting on a potential windfall, with no increase in production required.

²² Forecasted prices refer to the prices used in the fall 2015 Alberta government budget. Current (January 2016) market prices for futures are notably lower.

FIGURE 8 OIL SANDS ROYALTY PROJECTIONS



Source: Royalty Review Panel Report, p. 80.

CONCLUSION

The focus of the panel’s recommendations is on improving the structure of the crude oil, liquids and natural gas royalty framework – on a go-forward basis – in an attempt to increase the size of the pie, not change the way it is sliced.

Current oil and gas operations should be largely unaffected by the recommended changes. For oil sands, the rate and structure remain the same; current projects are now accountable to better monitoring and more transparency of their costs. For crude oil, liquids and natural gas, all current operations remain under the current system for the next 10 years. This provides regulatory stability and certainty to existing operations. The recommended changes to the crude oil, liquids and natural gas royalty framework apply to all new wells drilled in 2017 and beyond.

The panel's findings emphasized the changing landscape in which Alberta's resources compete. The panel notes that to compete, Alberta's royalty framework must reward innovation, eliminate inefficient behaviour and update over time:

- By replacing existing drilling programs with a single drilling and completion cost allowance that is better aligned with costs, the proposed *modernized royalty framework* removes inefficient distortions and better targets the rent, creating a setting that encourages greater levels of investment;
- By using independent measures for costs, as opposed to actual costs, the recommended framework also increases companies' incentive to innovate, and avoids the administrative burden of complex and costly monitoring;
- By recommending more transparency for allowable costs in the oil sands, Albertans can have greater confidence as to the validity of the costs being deducted in the calculation of royalties.

This royalty review is all about growing the value Albertans as owners receive from their resource. Collecting royalties in a more efficient manner is a great place to start.

APPENDIX: ECONOMICS PRIMER ON ROYALTIES, RENTS AND EFFICIENT TAXES

What are royalties?

Simply put, royalties are payments made to the owner of a resource for the right to extract the resource.

Who owns the mineral rights in Alberta?

Alberta's mineral rights have an interesting history. The first European control of Alberta was by the Hudson's Bay Company. In 1870, HBC surrendered the territory in exchange for approximately one million hectares of land. Subsequent settlers to Alberta gained access to both surface and mineral rights when purchasing homesteads, but in 1887, the Canadian government declared that the Crown should retain all mineral rights. Railroads subsequently received mineral rights as part of incentives to build the pan-Canadian rail lines. These rights remain to this day, and make up a large part of what is held by Prairie Sky Royalty Ltd., and other freehold royalty companies. In 1930, the federal rights were transferred to provincial ownership where they remain to this day. Currently, the province owns and administers - on behalf of Albertans - 81 per cent of the mineral rights, with the remaining 19 per cent held by the successors to HBC, railroads, private companies that have acquired these lands, federal agencies (e.g. Parks Canada), First Nations and individual freehold owners.

Source: *Alberta Energy*.

http://www.energy.alberta.ca/Tenure/pdfs/FMT_historical_overview.pdf

To an economist, royalties are meant to collect the resource rent attributable to the extraction of a scarce resource. The resource rent is defined as the excess return from an economic activity over and above all of the costs of undertaking the activity, including the opportunity cost of the capital investment required.²³ In other words, think of it as what is left over from the sale of a resource (i.e. the revenue) after subtracting all the costs to explore, develop, produce and deliver the resource, including a return on capital that is competitive with what could be earned on comparably risky investments elsewhere (i.e. the risk-adjusted return on capital). It is precisely this excess return, or resource rent, that Albertans as resource owners have a claim to, and it is this same rent that we should aim to collect via royalties.^{24,25}

Why should we aim to tax the rent?

Taxes have two effects: to collect revenue and change behaviour. In the case of an environmental tax (e.g. carbon), the latter is the goal. But in general, an efficient tax is one

²³ Opportunity cost is defined as the value of the best alternative forgone, where a choice needs to be made between several mutually exclusive alternatives given limited resources.

²⁴ Part of the resource rent accrues to Albertans through the auctioning of Crown leases for the right to drill for oil and gas. Royalties collect payments during the production stage.

²⁵ In a recent paper by Robin Boadway ("Tax Policy for a Rent-Rich Economy," *Canadian Public Policy*, 41:4, December 2015), the author argues that identifying what is a resource rent versus what is a return on risk is not an easy task. In the case of multi-period assets, such as oil and gas developments, the challenge is even more acute. A windfall profit in one year may appear as an excess return, but may be required to cover other years of insufficient return.

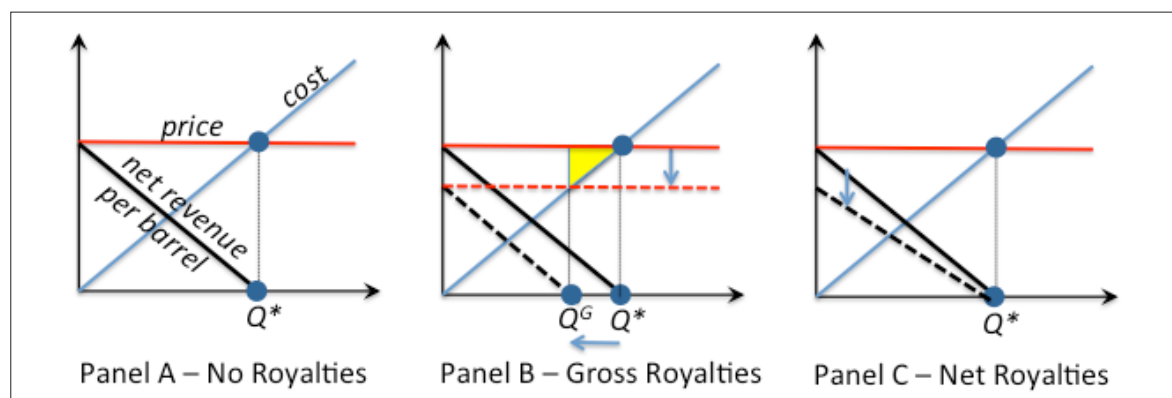
that collects revenue while leaving behaviour unchanged as much as possible. This is what economists would call “minimizing distortions.”²⁶

So long as a firm anticipates earning its risk-adjusted return on capital, it should invest whether it receives 100 per cent or none of the excess returns. When calculated correctly, these excess returns, or rents, are simply the gravy. In other words, economists consider a tax on rents an efficient tax, in that it leaves investment behaviour unchanged.

Alberta’s current royalty framework works in two ways. In the oil sands, royalties are initially levied at a low rate on gross revenues until cumulative revenues from a project equal cumulative costs, after which a higher royalty rate is applied to net revenues. In many ways, this approximates a rent tax. Crude oil, liquids and natural gas, however, are charged a royalty on gross revenues throughout the life of a well. While there are programs aimed at reflecting costs, this gross revenue-based royalty regime is not an efficient tax in that it can distort investment decisions and production behaviour.²⁷

To illustrate this point, consider an industry of many oil wells along the horizontal axis facing the same price but increasing in their costs of production, as illustrated in the following graphs. Net revenue per barrel is simply the difference between price and cost. Cost meets price at the point where the marginal well is right at the edge of producing or not (i.e. where net revenues per barrel are zero). In Panel A, the case with no royalties, we denote total industry-wide output as Q^* .

FIGURE A1 COMPARISON OF REVENUES AND PRODUCTION UNDER NO, GROSS AND NET ROYALTIES



Now consider what happens when royalties are applied to gross revenue in Panel B. The effective price drops, causing net revenues per barrel to shift down as well, and the new intersection between price and cost moves to the left. The total quantity produced is now lower, at Q^G . The shaded area in yellow represents the lost economic rent as a result of the distortion attributable to a gross royalty framework.

Instead, consider a tax applied to net revenues (our proxy for rent in this example) in Panel C. In this case, where net revenues are higher, the tax has a larger effect in dollar terms. At

²⁶ For a thorough overview of efficient taxation of resources, see: Boadway, Robin and Keen, Michael, “Theoretical Perspectives on Resource,” *Taxation of Petroleum and Minerals*, 24:13, 2010.

²⁷ Ibid.

the point where net revenues per barrel are zero, this tax has no effect. This causes the net-revenue-per-barrel line to rotate downwards. Importantly, this has no effect on the marginal well. The total quantity produced, Q^* , is unchanged. This illustrates the no-distortion, or efficient, tax result.

So why don't we have a rent tax?

During the review, the C. D. Howe Institute published a note (which was submitted to the panel) arguing that a cash flow tax is what Alberta should adopt.^{28,29} By setting the base of taxation as the difference between collected revenues and actual costs, the cash flow tax targets the rent. This hits all the good notes mentioned above. In fact, Alberta's current oil sands royalty framework is designed in this manner, closely approximating a rent tax. But there are two arguments why this is not what Alberta has in place outside the oil sands:

1. Alberta has over 100,000 wells in operation. The province is at an information disadvantage compared to companies in terms of knowing what their costs are (i.e. the companies know them; the province does not). For companies with multiple projects in multiple jurisdictions, how do we determine the share of company costs that are attributable to a specific well in Grande Prairie, AB, versus one in, say, Estevan, SK? This information disadvantage is also a problem faced in the oil sands, where the royalty framework does follow a variant of a cash flow tax. But at least in that case, there are only dozens of projects, not hundreds of thousands. The administrative burden on the province of monitoring and auditing allowable costs on thousands of wells would be large;
2. Using actual costs reduces a company's incentive to innovate. In a cash flow tax, reducing costs increases profitability but the firms do not appropriate the full gain. The province appropriates part of this gain from increased royalties (less cost deductions). By retaining independence from actual costs, companies appropriate the full benefit of their cost reductions. This means more return on cost-saving investments, resulting in lower costs and greater resource rent over time.

The recommended framework for crude oil, liquids and natural gas comes much closer to achieving the efficiency outcomes from a rent tax, as suggested by the C. D. Howe report, by approximating a revenue-minus-costs approach. This maintains the strong incentive to innovate, with a much smaller administrative burden.

²⁸ Boadway, R. and Dachis, B., "Drilling Down on Royalties: How Canadian Provinces Can Improve Non-Renewable Resource Taxes," *C. D. Howe Commentary*, No. 435, September 2015.

²⁹ This paper is one of many in a large literature evaluating the merits of cash flow taxes relative to other forms of resource taxation.

About the Author

Blake Shaffer is a PhD candidate in economics at the University of Calgary. Blake holds a MPhil in economics from the University of Cambridge, and a BSc (Honours) in environmental sciences from Queen's University. Prior to entering the PhD program, Blake enjoyed a 15-year career in the energy industry, most recently as head trader at TransAlta Corp., and previously as senior energy trader and analyst at Barclays Capital (N.Y.) and Powerex (B.C. Hydro). Blake was a member of the royalty review's natural gas expert working group, and assisted the panel in the development of its report.

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