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The University of Calgary is home to scholars in 16 faculties (offering more than 80 academic programs) and 36 Research Institutes and Centres including *The School of Public Policy*. Founded by Jack Mintz, now President's Fellow, and supported by more than 100 academics and researchers, the work of The School of Public Policy and its students contributes to a more meaningful and informed public debate on fiscal, social, energy, environmental and international issues to improve Canada's and Alberta's economic and social performance.

A PRIMER ON ALBERTA'S OIL SANDS ROYALTIES*

Sarah Dobson

EXECUTIVE SUMMARY

Fulfilling its campaign promise, the new NDP government announced a review of Alberta's royalty framework in June 2015. The province receives royalty revenue from three main sources – natural gas, crude oil, and oil sands. Since the 2009-10 fiscal year the largest contributor to Alberta's royalty revenues has been the oil sands. If you want a sense of how important oil sands royalties have been for Alberta's finances, consider this: In the 2014–15 fiscal year, the government collected just over $5 billion from oil sands royalties. These royalties covered over 10 per cent of the province's operational expenses of $48.6 billion in the same fiscal year.

Over the last six fiscal years the oil sands have contributed an average of 10 per cent of revenues to provincial coffers. This makes oil sands royalties the fourth largest contributor behind personal income taxes (23 per cent), federal transfers (13 per cent) and corporate income taxes (11 per cent).

But how many Albertans really understand how the royalty system works? What do we mean when we say "royalty"? How does the Alberta Government calculate royalties on oil sands producers? If the system is going to change, it's important that Albertans understand how the current system works.

That is what this paper is designed to do. For Albertans to properly judge the impact of new policy, they need a solid understanding of the current policy environment. We all know that oil prices have dropped and oil sands producers are losing profitability. As such, changes to the royalty system could have a deep and profound impact on the sector.

Here are some of the issues this primer will study:

- Pre-payout projects vs. post-payout projects, in other words, the classification of projects for royalty purposes based on whether the cumulative costs of a project exceed its cumulative revenues
- Monthly payment of royalties vs. annual payment
- Understanding the unit price of bitumen and how that price is applied
- Gross vs. net revenues and the application of royalties
- How the price of oil and the exchange rate between Canadian and U.S. dollars impact royalties
- The historical and forecast contribution of oil sands royalties to Alberta's finances

Needless to say, a primer like this should be required reading for policymakers. It should also be required reading, however, for any Albertan who cares about the long-term benefit of the oil sands to Alberta's revenue, and our financial future as a province.

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INTRODUCTION AUX REDEVANCES SUR LES SABLES PÉTROLIFÈRES DE L'ALBERTA

Sarah Dobson

SOMMAIRE

Fidèle à sa promesse électorale, le nouveau gouvernement néo-démocrate a annoncé un examen du régime de redevances de l'Alberta en juin 2015. La province reçoit des revenus en redevances de trois sources principales : gaz naturel, pétrole brut et sables pétrolifères. Depuis l'exercice financier 2009-10, ce sont les sables pétrolifères qui ont été le plus important contributeur aux revenus en redevances de l'Alberta. Si vous voulez vous faire une idée de l'importance des sables pétrolifères pour les finances de l'Alberta, considérez ceci : au cours de l'exercice financier 2014–15, le gouvernement a perçu un peu plus de 5 milliards de dollars en redevances sur les sables pétrolifères. Ces redevances ont couvert plus de 10 pour cent des dépenses de fonctionnement de la province, qui se sont élevées à 48,6 milliards de dollars pour le même exercice financier.

Au cours des six derniers exercices financiers, les sables pétrolifères ont représenté en moyenne 10 pour cent des revenus de la province. Cela fait des redevances provenant des sables pétrolifères le quatrième cotisant en importance derrière l'impôt des particuliers (23 pour cent), les transferts fédéraux (13 pour cent) et l'impôt sur le revenu des sociétés (11 pour cent).

Combien d'Albertains comprennent-ils vraiment comment fonctionne le régime de redevances ? De quoi parlons-nous lorsque nous disons « redevances » ? Comment le gouvernement albertain calcule-t-il les redevances des producteurs de sables pétrolifères ? Si le régime doit changer, il est important que les Albertains comprennent comment le régime actuel fonctionne.

C'est l'objectif que vise la présente étude. Pour que les Albertains évaluent adéquatement l'incidence de la nouvelle politique, ils ont besoin d'une solide compréhension de l'environnement politique actuel. Nous savons tous que le prix du pétrole a chuté et que la profitabilité des producteurs de sables pétrolifères est à la baisse. Dans ce contexte, les modifications au régime de redevances pourraient avoir une profonde incidence sur ce secteur.

Voici quelques-unes des questions que nous examinerons dans notre étude :

- Projets avant le recouvrement vs projets après le recouvrement, en d'autres termes, classification des projets aux fins des redevances selon que les coûts cumulatifs d'un projet dépassent ses revenus cumulés
- Paiement mensuel des redevances vs paiement annuel
- Compréhension du prix unitaire du bitume et du mode d'application de ce prix
- Revenus bruts vs revenus nets et application des redevances
- Comment le prix du pétrole et le taux de change des dollars canadiens et américains influent sur les redevances
- Contribution historique et prévue des redevances sur les sables pétrolifères aux finances de l'Alberta

Il va sans dire qu'une présentation telle que celle-ci devrait être une lecture obligatoire pour les responsables des politiques. Elle devrait également être une lecture obligatoire pour tous les Albertains qui se soucient des bénéfices à long terme des sables pétrolifères pour les revenus de l'Alberta, ainsi que pour notre avenir financier en tant que province.

* Cette recherche a été soutenue financièrement en partie par le gouvernement du Canada via Diversification de l'économie de l'Ouest Canada.

Les communiqués de l'École de politique publique sont de courts articles portant sur une question particulière de politique publique et visent à fournir au lecteur une analyse concise, critique et ciblée.

L'Université de Calgary regroupe des chercheurs dans 16 facultés (et proposent plus de 80 programmes d'études) et 36 instituts et centres de recherche, notamment l'École de politique publique. Fondée par Jack Mintz, maintenant President's Fellow, et avec la collaboration de plus de 100 enseignants et chercheurs, les travaux de l'École de politique publique et de ses étudiants contribuent à un débat public étayé sur les questions financières, sociales, énergétiques, environnementales et internationales, pour améliorer le rendement économique et social du Canada et de l'Alberta.

INTRODUCTION

In May 2015, Alberta elected a majority NDP government. Amongst the promises made on the campaign trail, the NDP committed to completing a review of royalty rates and tax incentives for the energy resource industry.[1] This commitment was reiterated in the government's first throne speech on June 14, 2015.[2] Less than two weeks later, Minister of Energy Margaret McCuaig-Boyd named Dave Mowat, the president and CEO of ATB Financial, as chair of the province's royalty review advisory panel. She also committed to having the review completed by the end of 2015.[3,4]

The remaining royalty review panel members were announced in August 2015, and the government launched an interactive website, "Let's Talk Royalties,"[5] to provide a forum for public participation in the royalty review process. Multiple stakeholder and community engagement sessions were also held through the fall of 2015.

While the government has made a concerted effort to involve the public in the royalty review process, much of the information that has been provided on the province's current royalty system provides only a high-level overview. This primer is aimed at the reader who is seeking a more detailed understanding of how Alberta's current oil sands royalty regime functions. I focus on the oil sands as it is currently the largest source of royalty revenue for the province, and is expected to be the largest future contributor to Alberta's resource revenues.[6]

BACKGROUND TO THE OIL SANDS ROYALTY REGIME

The oil sands are a mixture of sand, water, clay and bitumen, which is a heavy and viscous crude oil.[7] Oil sands projects pay royalties only on the production of bitumen, which is separated from the oil sands during the extraction process. Bitumen by itself has little to no value; overcoming its high viscosity and transforming it into a useful hydrocarbon product is technology-intensive and requires massive inputs of resources—energy, water, steel and labour—and capital.

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1 CBC News, "NDP platform promises to reverse cuts, raise corporate taxes," April 19, 2015, http://www.cbc.ca/news/elections/alberta-votes/ndp-platform-promises-to-reverse-cuts-raise-corporate-taxes-1.3039816.

2 Government of Alberta, "Speech from the Throne: June 15, 2015, First session of the twenty-ninth legislature," June 15, 2015, http://alberta.ca/release.cfm?xID=38187AFEDC714-0E6A-6F93-BC6A2C3B767D9AD9.

3 Government of Alberta, "Province names chair of royalty review advisory panel," June 26, 2015, http://alberta.ca/release.cfm?xID=38241E4AE2C13-F854-12DF-B671F31E824DAE93.

4 The government announced in mid-December 2015 that the results of the royalty review will be delayed until January 2016. Previously it had announced that any changes to the royalty system that result from the review will not take effect until 2017 at the earliest.

5 https://letstalkroyalties.ca/.

6 Government of Alberta, *Budget 2015: Supporting Jobs, Supporting Families, The Alberta Way* (October 2015), http://finance.alberta.ca/publications/budget/budget2015-october/fiscal-plan-complete.pdf.

7 Government of Alberta, Alberta Energy, "What is Oil Sands?" http://www.energy.gov.ab.ca/oilsands/793.asp.

The oil sands business therefore differs markedly from that of conventional oil and gas. Investments in oil sands projects are usually in the billions of dollars, projects take several years to plan, receive regulatory approval and construct, and it is several more years beyond that before a project starts to return its initial investment. As such, they present huge commercial risks. To help alleviate these risks, 40 years ago the governments of Alberta and Canada took a project-by-project approach with grants, loans, loan guarantees and special "uplifts" to encourage oil sands developments such as Suncor, Syncrude and Cold Lake. After at least two failed attempts in the 1980s to negotiate terms for additional, integrated oil sands mining projects, it became evident that this project-specific approach was not working to achieve the balance of interests needed for sustained investment. So, the generic royalty regime was devised. Alberta's first generic royalty regime came into effect in 1997. The current regime—described here—has been in place since 2009.

The philosophy behind the generic regime was simple: the government owner of the bitumen, recognizing the high front-end development costs, would be a "partner" and share in the risk by waiting to receive the bulk of its share of revenues until after the operator had recovered its costs, including the opportunity cost of capital. Thus, the notion of "payout" was introduced. Moreover, the government would recognize the operator's cost of capital expended prior to payout—but not entirely. A return allowance on all the upfront costs would be allowed, but at the Government of Canada's Long-Term Bond Rate, which is lower than the companies' cost of capital, thereby ensuring the province would start receiving a larger share of revenue sooner than if the operator's cost of capital were applied.[8]

Alberta's generic royalty regime is largely consistent with recognized best practices in how to structure a resource rent tax. Specifically, a resource rent is defined as the value of a resource beyond all extraction costs, including startup costs that are incurred prior to extraction even beginning. Following this definition, a resource rent tax should target only those profits that are earned after the cumulative revenues of a resource-extraction project exceed its cumulative costs. This approach is recommended by the International Monetary Fund and has been implemented in numerous countries around the world, including Australia and a number of countries in Africa.[9]

KEY DISTINCTIONS AND DEFINITIONS FOR OIL SANDS ROYALTIES

For the purposes of royalty calculations, an oil sands project is classified as either "pre-payout" or "post-payout." The distinction is based on whether the project's gross costs—dating back to its initial development stages—are exceeded by its gross revenues. That is, has the project earned more than it has spent over its entire lifetime from development to production? If not, then the project is classified as pre-payout and pays a "gross royalty," a set percentage of gross *monthly* revenues. If it has recovered its costs, then the project is classified as post-payout, in which case it pays a higher percentage royalty that may be based

8 For a description of the original generic oil sands royalty regime, refer to Robert Mitchell et al., "Alberta's Oil Sands: Update on the Generic Royalty Regime," presented at 7th UNITAR Symposium, October 27-31, 1998, available at http://www.energy.alberta.ca/OilSands/1190.asp.

9 For a further discussion on this structure of a resource rent tax see: Bryan C. Land, "Resource Rent Taxes: A re-appraisal," in *The Taxation of Petroleum and Minerals: Principles, Problems and Practice*, ed. Philip Daniel, Michael Keen and Charles McPherson (International Monetary Fund, 2010).

on the project's *annual* net or gross revenues. The royalty percentage depends primarily on the oil price—the average *monthly* price for pre-payout projects and the average *annual* price for post-payout projects. Exactly how these royalties are calculated will be discussed in more detail in the next section.

The payout date is the date at which the project's cumulative gross revenues equal the project's cumulative gross costs. Gross costs include all of the project's capital costs, the operating costs and the gross royalty that the project pays while in pre-payout status—and the investment return allowance on all these gross costs to date.

The investment return allowance is set monthly and reflects a project's opportunity cost of all costs incurred to date; or alternatively, the interest that could have been earned in the financial market on all this capital. For example, if a company has $1 billion invested in a project at the end of a period and the investment return allowance for that period is 2.5 per cent, then a project can claim an additional $25 million dollars in costs (2.5 per cent of $1 billion). As noted above, the return allowance is based on the long-term benchmark bond rates reported by the Bank of Canada.[10]

By defining separate royalties for pre- and post-payout projects, the royalty system accounts for the unique economics of oil sands projects, which require high upfront capital investments, but also operate at sustained high production levels for decades after their startup dates. For example, the under-construction Fort Hills oil sands mine, a joint venture by Suncor, Total SA and Teck Resources Ltd., with an anticipated startup date of 2017, has estimated capital costs of $13.5 billion and an anticipated operating life of 50 years.[11]

It is worth noting at this point that the status of an oil sands project is project-specific and not company-specific. That is, for companies with multiple oil sands projects, the status of any one project depends only on cumulative gross costs and revenues that are specific to that project. So a company can be paying different royalties on different projects at any one time. This, again, is a mechanism that encourages investment in the oil sands as it ensures all projects—regardless of ownership—are subject to the same royalty regime in the initial production years.

A key component that determines gross and net revenues for all project types is the unit price. The unit price is the value—for royalty purposes—that is assigned to a project's bitumen production. The unit price is project-specific as opposed to company-specific and its calculation depends on what happens to the bitumen after it passes the royalty calculation point. If the bitumen is sold to a third party for further processing, then the unit price is based on the unit value of these sales. Alternatively, if a company maintains ownership of the bitumen and further processes it internally—for example, upgrading the bitumen to synthetic

[10] Specifically, the return allowance for a particular month is equal to the average of the Bank of Canada's weekly reported long-term bond yields for that month, divided by 12 to adjust from an annual to a monthly rate. Historical data on weekly long-term bond yields from the Bank of Canada are reported in series V80691327, available at http://www.bankofcanada.ca/rates/interest-rates/lookup-bond-yields/. Source: Government of Alberta, "Monthly LTBR and Return Allowance Rate: 2015," http://www.energy.alberta.ca/OilSands/pdfs/LTBR2015.pdf.

[11] Jeffrey Jones, "Oil's plunge threatens Suncor's Fort Hills development," *The Globe and Mail*, January 6, 2015, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/sinking-crude-prices-could-put-suncors-fort-hills-project-on-hold/article22321243/.

crude oil at a company-owned upgrader—then the unit price is an approximation of the bitumen's fair market value.[12]

Gross revenues for a pre- or post-payout project are equal to the unit price of the project's bitumen production multiplied by total production. Net revenues for a post-payout project are equal to gross revenues minus allowed costs of production. The largest component of allowed costs are typically a project's operating expenditures, including, for example, employee salaries and inputs to the production process such as natural gas and electricity.[13]

THE CURRENT OIL SANDS ROYALTY REGIME

Under Alberta's current oil sands royalty regime, pre-payout projects pay a royalty based on gross revenues from project production. As shown in Figure 1, the gross-revenue royalty rate ranges from a low of one per cent at a WTI price of $55 (CAD) and below, to a high of nine per cent at a WTI price of $120 (CAD) and above. Between $55 and $120, the gross-revenue royalty rate increases by 0.12 per cent for every $1 (CAD) increase in the WTI price.

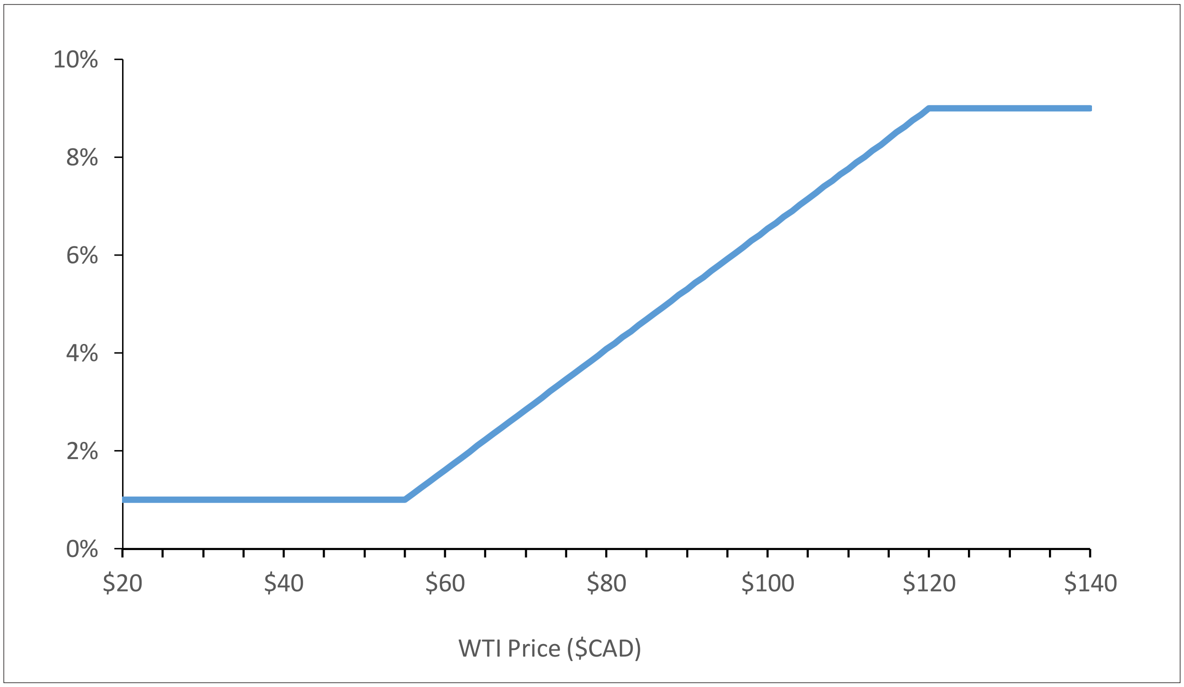
As noted previously, for pre-payout projects the period for royalty calculation and payment is monthly. Accordingly, the royalty rate is calculated using the average monthly WTI price and the average monthly exchange rate between Canadian and U.S. dollars. A summary of gross-revenue royalty rates for pre-payout projects for January through November 2015 is provided in Table 1.

As the pre-payout royalty is based primarily on monthly oil prices, a fall in the price of oil will immediately be matched by a fall in royalties owing. This will delay a project's payout date and extend the time that the project remains in pre-payout status and faces a lower royalty liability. A project's payout date can also be delayed if a project encounters costs that are higher than anticipated. This represents a form of risk sharing between the government and a project.

[12] For details on how the fair market value is calculated, see Government of Alberta, *Bitumen Valuation Methodology (Ministerial) Regulation* (2008), http://www.qp.alberta.ca/documents/Regs/2008_232.pdf.

[13] For a full description of allowed costs, see Government of Alberta, *Oil Sands Allowed Costs (Ministerial) Regulation* (2008), http://www.qp.alberta.ca/documents/Regs/2008_231.pdf.

FIGURE 1 GROSS-REVENUE ROYALTY RATE



Source: Author's calculations based on the gross-revenue royalty rate formula found in the Alberta Oil Sands Royalty Guidelines: Principles and Procedures (January 31, 2015), available at http://www.energy.alberta.ca/OilSands/pdfs/Royalty-Guidelines-2015.pdf.

TABLE 1 2015 GROSS-REVENUE ROYALTY RATES FOR PRE-PAYOUT PROJECTS

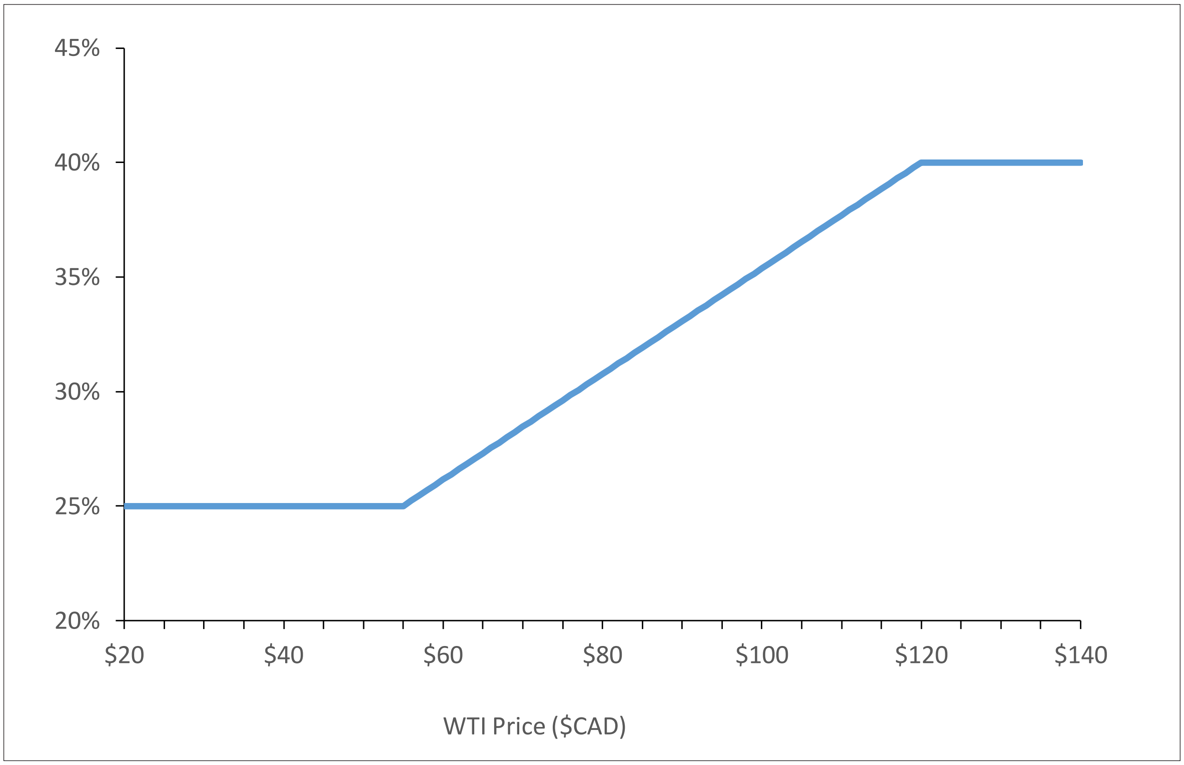
Month	WTI Price ($USD)	CAD/USD Exchange Rate	WTI Price ($CAD)	Gross-Revenue Royalty Rate
January	$59.29	0.82541005	$71.83	3.07%
February	$47.33	0.79999663	$59.16	1.51%
March	$50.72	0.79244726	$64.00	2.11%
April	$47.85	0.81095484	$59.00	1.49%
May	$54.63	0.82069127	$66.57	2.42%
June	$59.37	0.80866596	$73.42	3.27%
July	$59.83	0.77732748	$76.97	3.70%
August	$50.93	0.76053146	$66.97	2.47%
September	$42.89	0.75375261	$56.90	1.23%
October	$45.47	0.76495487	$59.44	1.55%
November	$46.29	0.75299220	$61.47	1.80%

Source: Alberta Energy, Oil Sands Monthly Royalty Rates.

Post-payout projects pay the higher of a gross-revenue royalty, or a net-revenue royalty that is equal to a net-revenue royalty rate multiplied by net revenues from project production. As shown in Figure 2, the net-revenue royalty rate, like the gross-revenue royalty rate, varies over the WTI price range of $55 to $120 (CAD). Specifically, the net-revenue royalty rate ranges from a low of 25 per cent at a WTI price of $55 (CAD) and below, to a high of 40 per cent at a WTI price of $120 (CAD) and above. Between $55 and $120, the royalty rate increases by 0.23 per cent for every $1 (CAD) increase in the WTI price.

As noted previously, for post-payout projects, the period for royalty calculation and payment is the calendar year. However, projects are required to make monthly instalment payments based on the expected royalty rate for the calendar year. As a result, the expected annual-gross-revenue and annual-net-revenue royalty rates are calculated each month using the expected annual WTI price in U.S. dollars and the expected annual Canadian-U.S. currency exchange rate.

FIGURE 2 NET-REVENUE ROYALTY RATE



Source: Author's calculations based on the net-revenue royalty rate formula found in the Alberta Oil Sands Royalty Guidelines: Principles and Procedures (January 31, 2015), available at http://www.energy.alberta.ca/OilSands/pdfs/Royalty-Guidelines-2015.pdf.

A summary of these rates for the 2015 calendar year, as forecast by Alberta Energy in January, June and November 2015, is provided in Table 2. The estimated royalty rates change in each month based on the actual WTI price and exchange rate that is observed, as well as updates to the forecasts for the estimated WTI prices and exchange rates for the remainder of the year.

TABLE 2 2015 EXPECTED NET- AND GROSS-REVENUE ROYALTY RATES FOR POST-PAYOUT PROJECTS

Month	JANUARY 2015			JUNE 2015			NOVEMBER 2015		
	Act/ Est	WTI ($USD)	CAD/USD Exchange	Act/ Est	WTI ($USD)	CAD/USD Exchange	Act/ Est	WTI ($USD)	CAD/USD Exchange
January	Act	$59.29	0.82541005	Act	$59.29	0.82541005	Act	$59.29	0.82541005
February	Est	$47.33	0.90500000	Act	$47.33	0.79999663	Act	$47.33	0.79999663
March	Est	$48.24	0.90500000	Act	$50.72	0.79244726	Act	$50.72	0.79244726
April	Est	$48.99	0.90500000	Act	$47.85	0.81095484	Act	$47.85	0.81095484
May	Est	$50.07	0.90500000	Act	$54.63	0.82069127	Act	$54.63	0.82069127
June	Est	$51.22	0.90500000	Act	$59.37	0.80866596	Act	$59.37	0.80866596
July	Est	$52.37	0.90500000	Est	$59.83	0.81500000	Act	$59.83	0.77732748
August	Est	$53.44	0.90500000	Est	$59.47	0.81500000	Act	$50.93	0.76053146
September	Est	$54.40	0.90500000	Est	$59.83	0.81500000	Act	$42.89	0.75375261
October	Est	$55.25	0.90500000	Est	$60.10	0.81500000	Act	$45.47	0.76495487
November	Est	$56.03	0.90500000	Est	$60.44	0.81500000	Act	$46.29	0.75299220
December	Est	$56.79	0.90500000	Est	$60.78	0.81500000	Est	$42.92	0.78000000
Annual Avg	Est	$52.78	0.89836750	Est	$56.64	0.81234717	Est	$50.63	0.78731039
Annual Avg WTI ($CAD)	Est		$58.76	Est		$69.72	Est		$64.30
Net-Revenue Royalty Rate	Est		25.87%	Est		28.40%	Est		27.15%
Gross-Revenue Royalty Rate	Est		1.46%	Est		2.81%	Est		1.80%

Source: Alberta Energy, Oil Sands Monthly Royalty Rates.

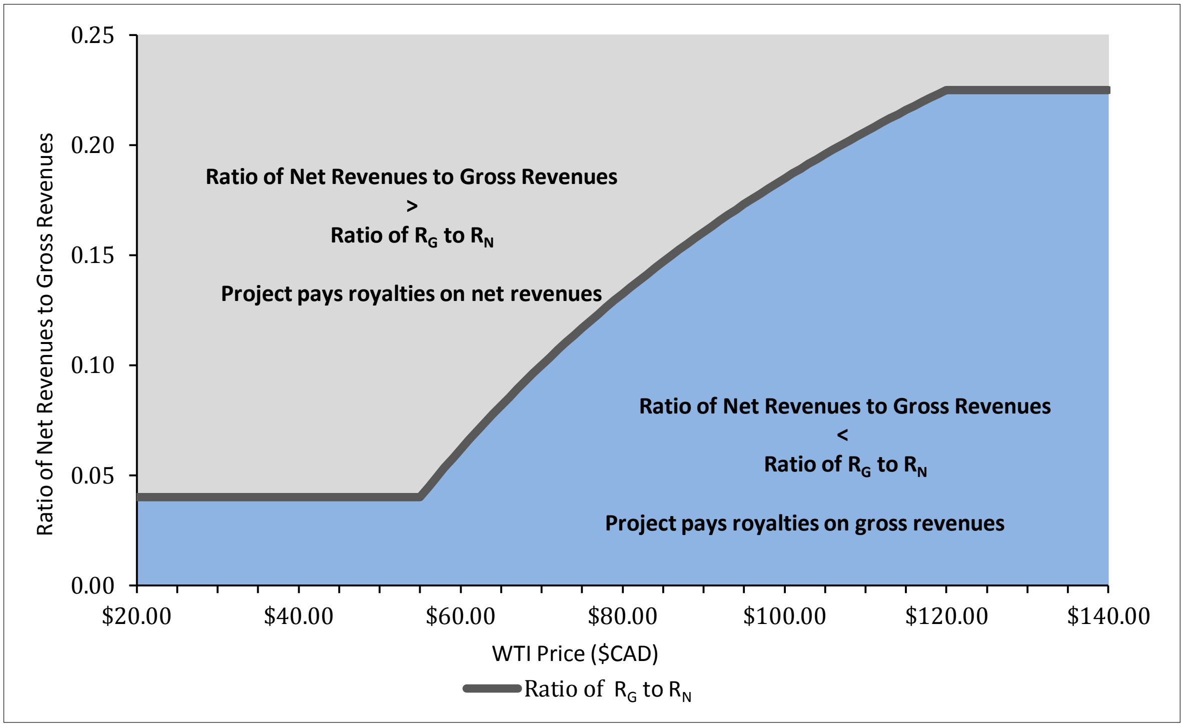
As post-payout projects pay a royalty that is based on the average *annual* oil price, the impact of a falling oil price on a project's royalty liability can be delayed. The price impact in 2014 provides the best example of this as the oil price fall started mid-year. As a result, the average annual oil price for 2014 was propped up by higher prices observed over the first half of the year and the gross- and net-revenue royalty rates for post-payout projects remained virtually unchanged over the second half of the year. The 2015 rates, however, have plummeted.[14] So the current royalty structure does provide royalty relief to post-payout projects during times of low oil prices—another mechanism that supports investment—but the timing of when the relief kicks in, and the degree of the relief, is highly dependent on when in the calendar year the oil price fall begins and how long the oil price remains low.

Post-payout projects receive some risk sharing against higher than anticipated costs through the net-revenue royalty. In particular, if a project faces a period with higher than expected costs, then its net revenues will be reduced and the project's net-revenue royalty will fall accordingly. There is a limit to the risk sharing for post-payout projects, however, and that is the gross-revenue royalty. More specifically, a post-payout project will always pay the higher of the net-revenue or gross-revenue royalty. So while the net-revenue royalty will be reduced by higher costs, the gross-revenue royalty is a lower limit that a project's royalty liability cannot fall below.

[14] For example, from June 2014 to December 2014 the expected annual post-payout net royalty rate for 2014 fell from 38.1 to 36.8 per cent. In January 2015, the expected net royalty rate for 2015 was 25.9 per cent. Source: Government of Alberta. Alberta Energy, "Monthly Royalty Rates," http://www.energy.alberta.ca/OilSands/1513.asp.

The higher royalty—net or gross—is determined by the relationship between the ratio of the gross-revenue royalty rate (R_G) to the net-revenue royalty rate (R_N) (hereafter referred to as the royalty ratio) and the ratio of a project's net revenues to gross revenues (hereafter referred to as the revenue ratio). Figure 3 plots the royalty ratio against the Canadian-dollar WTI price. When the revenue ratio is greater than the royalty ratio—when it falls above the plotted line in Figure 3—a project will pay royalties on its net revenues. Alternatively, when the revenue ratio is less than the royalty ratio—when it falls below the plotted line in Figure 3—a project will pay royalties on its gross revenues.

FIGURE 3 POST-PAYOUT PROJECTS: THRESHOLD FOR NET- VERSUS GROSS-REVENUE ROYALTIES



Source: Author's calculations based on the gross-and net-revenue royalty rate formulas found in the Alberta Oil Sands Royalty Guidelines: Principles and Procedures (January 31, 2015), available at http://www.energy.alberta.ca/OilSands/pdfs/Royalty-Guidelines-2015.pdf.

As shown in Figure 3, at a Canadian-dollar WTI price of $55 and below, only projects with a revenue ratio less than 0.04—implying capital and operating expenditures per unit that are more than 96 per cent of the unit price of the project's bitumen—will pay royalties on gross revenues. As the WTI price increases, the royalty ratio also increases. The maximum value of the royalty ratio is 0.23, reached at a Canadian-dollar WTI price of $120 and above. In this price range a project will pay a royalty on gross revenues only when its capital and operating expenditures per unit are in excess of 77 per cent of the unit price of the project's bitumen.

While the above explanation may suggest that projects are more likely to pay a gross-revenue royalty when the WTI price is high, it is actually the opposite that is true. To see this, let's assume the differential between the WTI price and the unit price of bitumen production is 40 per cent, just above the average from the first 10 months of 2015 (based on a comparison between the observed WTI price and the province's sample fair market valuation for bitumen production).[15] This implies Canadian-dollar WTI prices of $120 and $55 will correspond to bitumen prices of $72 and $33 respectively.

Seventy-seven per cent of $72 is $55.44, while 96 per cent of $33 is $31.68, implying that the minimum cost threshold to pay the gross-revenue royalty is much higher in the high-price scenario. Actual cash operating costs for projects by Canadian Natural Resources Ltd., Suncor, Cenovus and Syncrude have varied from $8 to $47 per barrel in 2014 and 2015.[16] This sample suggests there are no—or at best very few—projects that will pay a gross-revenue royalty when prices are high. Alternatively, the cost threshold for paying the gross-revenue royalty at low prices is within the range of observed operating costs for a number of projects.

Lastly, it is also worth noting that both the net-revenue royalty rate and the gross-revenue royalty rate (for pre- and post-payout projects) are impacted by changes in the Canadian-U.S. currency exchange rate. More specifically, all else being equal, when the Canadian dollar strengthens against the U.S. dollar—equivalent to the CAD/USD exchange rate increasing—the Canadian-dollar WTI price will fall and the royalty rate will be lower. Alternatively, when the Canadian dollar weakens against the U.S. dollar—equivalent to the CAD/USD exchange rate decreasing—the Canadian-dollar WTI price will increase and the royalty rate will be higher.

In general, energy producers are made worse off by a stronger Canadian dollar. A stronger Canadian dollar increases the relative price of Canadian oil in a global market, and output that is sold in U.S. dollars has a lower Canadian dollar value. The royalty regime has been designed to capture this negative impact—decreasing the royalty rate when the exchange rate falls.

Fluctuations in the exchange rate also tend to provide a slight smoothing effect to changes in the royalty rate. This is because the oil price and the CAD/USD exchange rate have opposite effects on the royalty rate and tend to move together. That is, a higher oil price is typically accompanied by a strengthening Canadian dollar and a lower oil price is typically accompanied by a weakening Canadian dollar. The strength of the relationship is under dispute—the Bank of Canada has described it as "loose but predictable," while others have

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[15] Author calculations using bitumen price data from the Government of Alberta's "BVM Model calculator" and WTI price data from the U.S. Energy Information Administration. Sources: Government of Alberta, Alberta Energy, "Bitumen Valuation Methodology (BVM) Components," http://www.energy.alberta.ca/OilSands/1542.asp; and U.S. Energy Information Administration, "Cushing, OK WTI Spot Price FOB," http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=D.

[16] Estimates of cash operating costs per barrel are based on reported values from 2015 first-quarter reports by Cenovus, Suncor, Canadian Natural Resources Ltd. and Canadian Oil Sands. Sources: (1) Cenovus Energy, *First Quarter 2015*, http://www.cenovus.com/invest/docs/2015/Q1-2015-quarterly-report.pdf; (2) Suncor Energy, *First Quarter 2015: Report to Shareholders*, http://www.suncor.com/pdf/Suncor_English_2015_Q1_Report.pdf; (3) Canadian Natural Resources Limited, *First Quarter Report: Three months ended March 31, 2015*, http://www.cnrl.com/upload/media_element/932/01/q115_interim-report.pdf; and (4) Canadian Oil Sands, *Q1 First Quarter Report*, http://www.cdnoilsands.com/files/FinancialReports/Q1-2015-Report_FINAL_v001_c28zy3.pdf.

argued there is a direct (positive) correlation between the price of oil and the exchange rate[17, 18, 19]—but it is widely acknowledged to exist.

The smoothing effect of the exchange rate tends to be slight, however, because although the exchange rate and oil price move together, the oil price is significantly more volatile and fluctuates over a much larger range. For example, from July 2014 to November 2015, the WTI price has fallen by 56 per cent—dropping from US$105.15 to US$46.29—while the CAD/USD exchange rate has fallen by less than 20 per cent—declining from 0.9312 to 0.7530.[20] As a result, the oil price tends to be the primary determinant of both the royalty rate and royalties collected.

THE CONTRIBUTION OF OIL SANDS ROYALTIES TO ALBERTA'S REVENUES

The sliding price scale for Alberta's oil sands royalty rates was introduced in 2009. As shown in Figure 4, from the 2009/10 to 2014/15 fiscal years, total oil sands royalties have ranged from $3.2 to $5.2 billion and their contribution to total government revenues has fluctuated between 8.9 and 11.5 per cent.[21] They have generally been the fourth-largest contributor to Alberta's revenues over this time period—falling behind personal income taxes, federal government transfers and corporate income taxes.[22]

Looking at oil sands royalties in comparison to government expenditures, as shown in Figure 5, in the 2014/15 fiscal year the value of royalties collected ($5.0 billion) was nearly sufficient to cover the entirety of the government's spending on advanced education ($5.4 billion).[23] Alternatively, oil sands royalties could contribute 26 per cent to the province's health care expenditures ($19.3 billion) or 67 per cent to education ($7.6 billion).

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[17] Stephen S. Poloz, "Float of the Loonie," Remarks (Bank of Canada, September 16, 2014), http://www.bankofcanada.ca/2014/09/float-of-the-loonie/.

[18] Werner Antweiler, "The Canadian Petrodollar," Werner's Blog (April 1, 2015), http://strategy.sauder.ubc.ca/antweiler/blog.php?item=2015-04-01.

[19] Geoffrey Morgan, "The petrodollar effect: Just how much is the loonie tied to oil prices?" *Financial Post*, November 27, 2014, http://business.financialpost.com/news/energy/the-petrodollar-effect-just-how-much-is-the-loonie-tied-to-oil-prices.

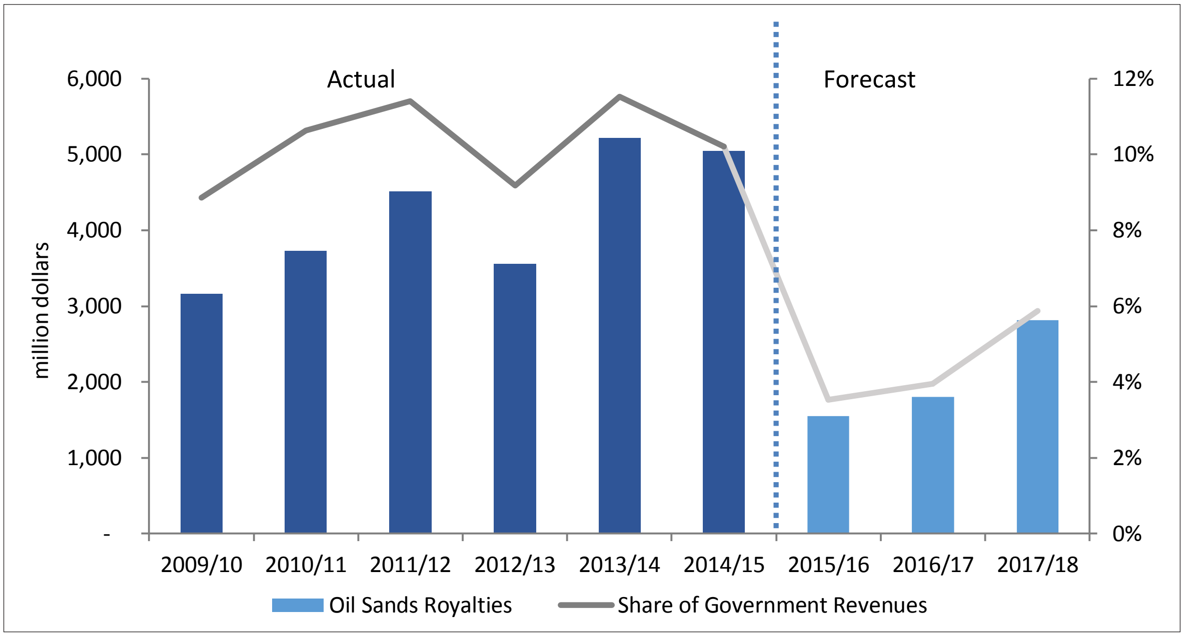
[20] Government of Alberta, "Monthly Royalty Rates".

[21] Author calculations. Source: Alberta Treasury Board and Finance, "Budget Documents and Quarterlies Index," http://finance.alberta.ca/publications/budget/index.html.

[22] The exceptions to this were fiscal years 2010/11 and 2011/12, when oil sands royalties exceeded corporate income taxes and were the third-largest contributor to government revenues.

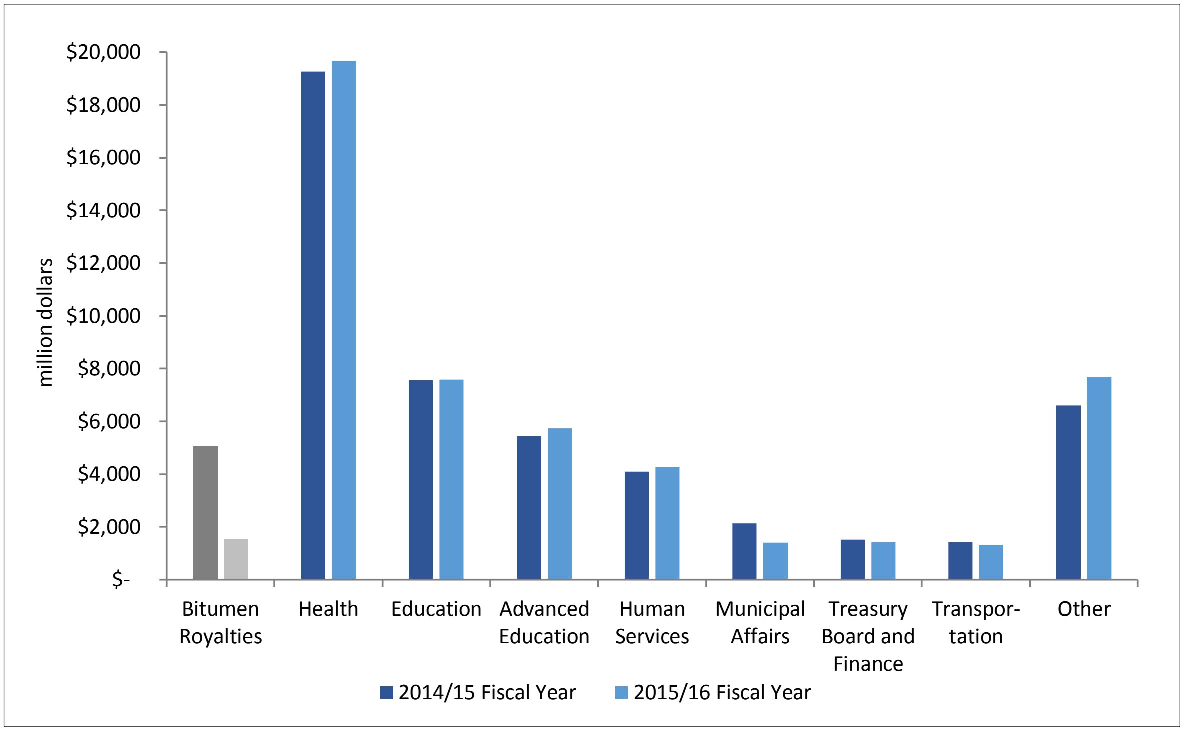
[23] Government of Alberta, *Budget 2015*.

FIGURE 4 ACTUAL AND FORECAST OIL SANDS ROYALTIES



Source: Alberta Treasury Board and Finance, Budget Documents and Quarterlies Index.

FIGURE 5 OIL SANDS ROYALTIES AND MINISTRY EXPENDITURES FOR THE 2014/15 AND 2015/16 FISCAL YEARS



Source: Government of Alberta, Budget 2015: Fiscal Plan Tables.

Note: The "Other" category includes 2013 Alberta Flood Assistance, Aboriginal Relations, Agriculture and Forestry, Culture and Tourism, Economic Development and Trade, Energy, Environment and Parks, Executive Council, Infrastructure, Jobs, Skills, Training and Labour, Justice and Solicitor General, Legislative Assembly, Seniors, Service Alberta and Status of Women.

The value of collected oil sands royalties has been influenced by production levels, the price of oil and the transition of projects from pre- to post-payout status. Annual oil sands production has steadily increased from 2009 to 2014, rising from 544-million to 841-million barrels of bitumen.[24] This steady growth in bitumen production has contributed to a significant increase in royalties from pre-payout projects. Alberta Energy only reports the breakdown between pre- and post-payout project royalties on an annual (as opposed to fiscal-year) basis. However, this shows pre-payout royalties increasing by over eight times—rising from $173 million in 2009 to $1,480 million in 2014.[25]

Over the 2009/10 to 2014/15 fiscal years, the influence of the oil price on royalties collected is most evident in the 2012/13 fiscal year when oil sands royalties fell to $3.6 billion from $4.5 billion the year prior, a decline of over 20 per cent.[26] The drop was precipitated in part by a decline in the WTI price—which fell by 3.1 per cent from a monthly average of $96.28 (CAD) in 2011/12 to $93.30 in 2012/13.[27] The larger contributor, however, was the growing differential between WTI and the price of heavy oil from the oil sands, which is benchmarked by the price of Western Canadian Select (WCS).[28] From 2011/12 to 2012/13, the price of WCS dropped by nearly 15 per cent, falling from an average of $80.02 (CAD) to $68.44.[29] This created a double negative hit on royalties—the lower WTI price put downward pressure on the royalty rate while the lower WCS price contributed to lower revenues for oil sands projects.

The prices of WTI and WCS recovered in 2013/14, rising to annual averages of $103.71 (CAD) and $80.04 (CAD) respectively. Royalties also recovered strongly, rising to a record level of $5.2 billion—nearly 16 per cent higher than the amount collected in the similar price environment of 2011/12. The rise in royalties can be attributed to incremental production from new projects and the application of higher royalty rates as projects transitioned from pre- to post-payout status.

Looking ahead, the expected values of oil sands royalties over the next three fiscal years are also shown in Figure 4. In the NDP budget for the 2015/16 fiscal year, released in October

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[24] Annual production data is obtained from the Alberta Energy Regulator report, *ST98: Alberta's Energy Reserves and Supply/Demand Outlook*. 2014 data is reported in ST98-2015 and 2009 data is reported in ST98-2010. Source: Alberta Energy Regulator website, "ST98: Alberta's Energy Reserves and Supply/Demand Outlook," http://aer.ca/data-and-publications/statistical-reports/st98.

[25] Government of Alberta, Alberta Energy, "Alberta Historical Royalty Data: Pre Payout Data," http://www.energy.gov.ab.ca/About_Us/1701.asp.

[26] Alberta Treasury Board and Finance, "Budget Documents and Quarterlies Index."

[27] Both the monthly average WTI prices converted from U.S. dollars and the monthly average exchange rate are obtained from the oil sands royalty rate information bulletins posted by Alberta Energy. The reported monthly average price for the fiscal year is the average of the monthly WTI prices in Canadian dollars. Source: Government of Alberta, "Monthly Royalty Rates," http://www.energy.alberta.ca/OilSands/1513.asp.

[28] WCS is a crude-oil stream consisting of heavy conventional and bitumen crude oils blended with diluents. The stream is comprised of production from Cenovus, Suncor Energy, Canadian Natural Resources Ltd. and Talisman Energy. The majority of the stream is exported to the U.S. Midwest for refining. Source: Alberta Government, *Alberta Official Statistics: Heavy Crude Oil Reference Prices, Monthly*, http://finance.alberta.ca/aboutalberta/osi/aos/data/Heavy-Crude-Oil-Reference-Prices.pdf.

[29] Monthly average WCS prices in U.S. dollars are obtained from the price archives of Sproule Associates Ltd. I convert these prices to Canadian dollars using the exchange rates provided in the monthly oil sands royalty rates information bulletins. Sources: Sproule Associates Ltd., "Sproule Archives: May 2015," http://www.sproule.com/forecasts/archives; and Government of Alberta, "Monthly Royalty Rates."

2015, the government forecast that oil sands royalties would fall to $1.5 billion in 2015/16.[30] This would be the lowest level since 2005/06 when royalties were only $950 million.[31] At $1.5 billion, bitumen royalties are expected to contribute only 3.5 per cent to government revenues. With respect to total government revenues, this puts royalties virtually even with the fuel tax, a revenue source that it has exceeded by an average of over 400 per cent over the last six fiscal years.

Oil sands royalties in comparison to government ministry expenditures for the 2015/16 fiscal year are shown in Figure 5. From 2014/15 to 2015/16, expected ministry expenditures are virtually unchanged, while expected royalties have plummeted by almost 70 per cent.[32] This highlights the risk of relying on an uncertain revenue stream to fund known expenditures that do not fluctuate much from one year to the next. Specifically, whereas oil sands royalties could virtually cover the government's entire budget for advanced education and innovation in 2014/15, in the 2015/16 fiscal year they are forecast to cover barely a quarter of that budget.[33] Similarly, the potential contribution to health care from oil sands royalties has fallen from 26 per cent to eight, and their potential contribution to education is down from 67 to 20 per cent.

The oil sands royalty forecasts for 2016/17 and 2017/18 are based on an expectation that the WTI price will follow a gradual recovery path, rising from an average of $76.00 (CAD) in 2016/17 to $83.00 in 2019/20.[34] The differential between the prices of WTI and WCS is expected to stay relatively constant at just under 10 per cent. Under the forecast conditions, oil sands royalties are expected to rise steadily from 2015/16 onwards, reaching $2.8 billion in 2017/18 and contributing just under six per cent to expected total government revenues of $47.9 billion.

CONCLUSION

The oil sands are Alberta's most significant extractible resource, with estimated remaining reserves of 166.3 billion barrels.[35] There are projects currently under construction with expected operating lives of up to 50 years, suggesting the oil sands are going to remain an important part of Alberta's economy for many years still to come. Having a royalty system that continues to encourage investment in the oil sands, while also ensuring that Albertans receive an optimal return from the development of the resource—two key objectives of the current royalty review[36]—is therefore a necessary and worthwhile goal.

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[30] Government of Alberta, *Budget 2015*.

[31] Alberta Treasury Board and Finance, "Budget Documents and Quarterlies Index."

[32] Government of Alberta, *Budget 2015*.

[33] Ibid.

[34] Ibid.

[35] Alberta Energy Regulator, *ST98-2015 Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015-2024* (June 2015), http://aer.ca/documents/sts/ST98/ST98-2015.pdf.

[36] Government of Alberta, *Alberta's Royalty Review 2015*, http://www.energy.alberta.ca/Org/pdfs/RRmandate.pdf.

My objective in this primer was to provide a description of Alberta's current oil sands royalty system. Key characteristics of the current system include the classification of projects according to payout status, a royalty for pre-payout projects that is based on gross project revenues, a royalty for post-payout projects that may be based on either net or gross project revenues, and having the royalty rate for pre- and post-payout projects depend on both the oil price and the exchange rate between Canadian and U.S. dollars. The review panel will need to look closely at this regime and consider whether it is effective, whether it is sufficient and what—if any—additional mechanisms are needed to ensure that Alberta's future royalty framework achieves the objectives of the current review.

About the Author

Sarah Dobson (PhD) is a Research Associate in the Energy and Environmental Policy area at The School of Public Policy. Her research interests are focused on studying the design, implementation and evaluation of energy and environmental regulatory policy. In prior work Sarah has considered such issues as the welfare implications of climate change policy, and the optimal design of regulatory policy to take into account the tradeoff between the economic benefits of resource development and the ecological consequences of management decisions. Sarah holds a PhD and MSc in Agricultural and Resource Economics from the University of California, Berkeley.