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E-BRIEF

October 7, 2021

ENERGY AND NATURAL RESOURCES POLICY

An Oil Sands Inequity: Alberta's Outdated Bitumen Valuation Program

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- Canada's oil sands accounted for 63 percent of oil production in Canada in 2019.[1] Royalties from oil sands production have been the source of 7.7 percent of Alberta's revenues since 2008 (Alberta 2020). Alberta regularly reviews the royalty regimes in place for oil and natural gas extraction, but there is some contention about the design of one particular component of the oil sands royalty: the Bitumen Valuation Methodology (BVM).
- The BVM is a government regulation that sets the price, and therefore influences the royalty paid, of bitumen that changes hands through non-market transactions – usually between affiliates, such as when oil sands production is sent to an upgrader owned by the same company.
- Our analysis shows, however, that the BVM leads to the payment of higher royalties than is the case for similar production not subject to the regulation. We argue that royalty price setting for all bitumen sales should be determined by market prices, not by administratively set formulas.

Given the substantial contribution made by Alberta's oil sands investments to the province's and Canada's economy, a stable, competitive and fair oil sands royalty regime that promotes investment is essential.

The authors thank Jeremy Kronick, Ramisha Asghar, Robin Boadway, Ben Brunnen, G. Kent Fellows, Andre Plourde, Bryan Remillard, Robert Rolfe and anonymous reviewers for comments on an earlier draft. The authors retain responsibility for any errors and the views expressed.

1 https://www.nrcan.gc.ca/science-and-data/data-and-analysis/energy-data-and-analysis/energy-facts/crude-oil-facts/20064#L4

Bitumen from oil sands is extracted either *in situ* or through surface mining, which is feasible only for deposits no deeper than 75 metres.[2] In Alberta, deposits in this range are found only in the Athabasca region, near Fort McMurray (Alberta 2021). After extraction, the bitumen is cleaned and processed into saleable products, primarily synthetic crude oil and dilbit (diluted bitumen). Box 1 describes the types of crude oil products made from oil sands.

There is an inequity in the current system that determines how much certain oil sands mines pay in royalties because of how the government determines the value of the bitumen they produce. The Bitumen Valuation Methodology that the Alberta government uses to value non-market transactions of bitumen production for royalty purposes has consistently overvalued that production, compared with market-determined values, by between $3 and $11 per barrel in recent years, thereby increasing calculated royalties for those producers.

We argue that royalty price setting for all bitumen sales should be determined by market prices, not by administratively set formulas. We recommend that the BVM rely on a principle of weighted-average third-party sales prices for regionally similar products to calculate bitumen prices, backstopped by market-based benchmark prices for western Canadian oil sands-diluted bitumen (dilbit). We also recommend removing the floor-price provision within the BVM.

Alberta's Oil Sands Royalty Regime

The methods producers use to extract bitumen from Alberta's oil sands differ greatly from those used in conventional oil production, resulting in different cost structures. Hence, the bitumen industry requires its own distinct royalty framework that would better balance the above-normal profits the province extracts from the industry while not discouraging investment.[3]

Alberta's oil sands royalty system uses a revenue-minus-cost framework based on a model of resource-rent extraction seen in many jurisdictions, typically applied to investments requiring high upfront capital investment. The royalties paid by each approved and defined project depend on several factors. When an oil sands project is first developed, it pays a certain rate prior to reaching "payout" – roughly speaking, the point at which the initial capital investment is recovered. Pre-payout projects pay a gross royalty rate as a set percentage of the project's gross monthly revenues. Post-payout projects pay a royalty rate on either net revenues or gross revenues – paying whichever generates the largest royalty payment. Both the gross royalty and the net royalty rate operate on a sliding scale that adjusts with the price of West Texas Intermediate (WTI) priced in Canadian dollars. WTI is an oil price benchmark for products of a similar composition as synthetic crude oil.[4] Royalties are paid monthly,

2 Deposits considerably deeper than this require *in situ* production. *In situ* methods require steam injection, which decreases the viscosity of the bitumen, allowing the combination of bitumen and water to be pumped to the surface, at which point the water must be separated out.

3 The Alberta government led a royalty review in 2015, but ultimately decided not to change the oil sands royalty framework, which is still in place today. It did make minor changes to the BVM policy and provided more transparency in data reporting. The 2015 review made the conventional royalty structure more like that of oil sands.

4 The gross revenue royalty rate ranges between 1 percent and 9 percent of gross revenues, whereas the net revenue royalty rate ranges between 25 percent and 40 percent of net revenues, based on changes in oil prices of between $55 and $110 per barrel of WTI.

Box 1: Types of Oil Sands Products

Upon extraction, bitumen is typically converted into either synthetic crude oil or diluted bitumen. The conversions are necessary, as bitumen is naturally too viscous to ship via pipeline on its own, and must be pure enough to meet pipeline specifications (*Oil Sands Magazine* n.d.). Another option exists through "partial upgrading," which involves converting bitumen or dilbit into medium- or heavy-density crude without the need for diluent for further transportation.

Synthetic crude oil: This is a light sweet crude – that is, with low viscosity and low sulphur content, changing the oil from "sour" to "sweet" – that can be easily transported through pipelines and processed in most refineries. Creating synthetic crude oil requires the bitumen to go through a process known as upgrading, a costly and technical procedure but one that fetches a price similar to light, sweet conventional oil produced in continental North America.

Diluted bitumen: This is generally a heavy sour crude – with high viscosity and high sulphur content – and is the combination of relatively pure bitumen diluted with a condensate created to transport and sell to third-party buyers without the need for high-cost upgraders. Most dilbit that is sold to third-party buyers is derived from *in situ* operations (except for some oil sands mines – namely Kearl and Fort Hills), and can be refined only at high-conversion refineries, predominantly located in the US Midwest and on the US Gulf Coast. Dilbit earns a lower price than light, sweet crude oils.

Partially upgraded bitumen: Another option that has garnered attention in recent years is to "partially upgrade" bitumen or dilbit into a medium or heavy crude without the need for diluent in transmission. The process is less costly than fully upgrading bitumen into synthetic crude oil, and would free up space on constrained pipelines, as diluent typically makes up about 30 percent of the volume of dilbit.[a] Partial upgrading, however, has not yet been proven as a commercially viable alternative.

a Latest estimates indicate that a partial upgrader with capacity for 100,000 barrels per day would cost approximately $3 billion relative to $10 billion for a full upgrader that produces synthetic crude oil (*Oil Sands Magazine* 2018).

although calculations for post-payout projects are "trued up" at the end of each reporting year to an annual calculation.

Royalties are determined for each specific project – that is, determined within a "ring fence" for each project – not on a company-wide basis. That requires determining a point at which the oil sands product leaves the ring-fenced investment and is subject to royalty. For projects that sell their bitumen to third parties through arm's-length sales, that market-based price determines the revenues per barrel used in royalty calculations. The bitumen value used in royalty calculations is intended to reflect the value of the cleaned bitumen itself at the location produced; activity such as diluent blending and further processing should not affect the bitumen price. For projects owned and operated by integrated companies that process the bitumen internally, the market price is harder to distinguish. Analogous to transfer prices used in accounting or taxation to reflect values in non-market transactions that exist in many industries, the Alberta government's solution to determining bitumen price for royalty purposes has been the BVM.

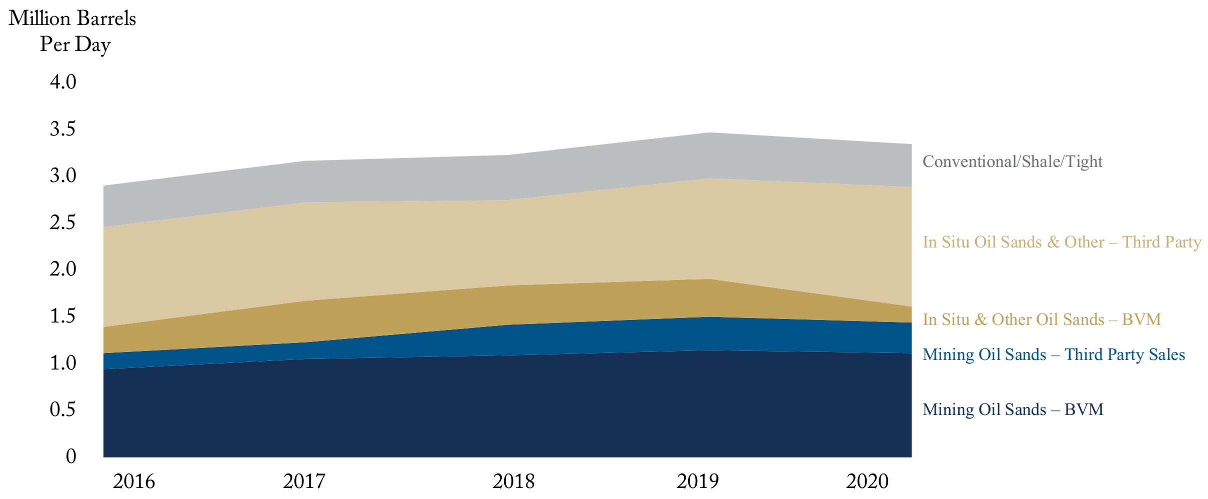
The Bitumen Valuation Methodology

Canada's 3 million barrels per day of oil sands production in 2019 was split about evenly between mining and *in situ* production, with conventional oil and other liquids adding another 1.8 million barrels per day. Facilities that produce just under half of oil sands production were subject to the BVM in some capacity during 2020 (Figure 1). Determining the exact volume of oil sands production subject to BVM is not possible because of data limitations, although it is possible to see which projects were subject to BVM at least once during the reporting period.

The annual amounts in Figure 1 report facilities that are subject to BVM in any one of the twelve months of the year. This makes the amount of bitumen produced from *in situ* and other means subject to BVM, as shown in Figure 1, a significant overestimate as many are only subject to BVM for a small share of their production. For oil sands mines subject to the BVM, we assume that all of their annual production – in 2020 representing 39 percent of total oil sands production and 77 percent of production from oil sands mines – was subject to the BVM over the period. These facilities are directly connected to upgraders. Thus, the most appropriate comparison to make is between mines subject to the BVM and mines not subject to the BVM.

As discussed further below, the BVM was introduced to ensure that resource owners (residents of the province, through the provincial government) were collecting royalties based on the correct market value of oil sands sold in non-market transactions. If the BVM value is less than the appropriate market value, the owners are not getting the correct share; if it collects too much, producers with non-market sales, such as to their own upgraders, might not have an incentive to invest enough, also potentially leading to resource owners not collecting as much as possible long-term. So, is the BVM ensuring that all types of producers pay royalties that reflect the same market value?

Figure 1: Alberta Crude Oil Production and Royalty Treatment, 2016–20



Notes: Volumes will be overstated for production subject to the BVM, and understated for production sold in the open market. Conventional volumes do not include condensate or other liquids.

Sources: Alberta 2021; Alberta Oil Sands Royalty Data; Canada Energy Regulator 2020.

The Difference between BVM and Non-BVM Prices

The BVM was designed to approximate a market price for the royalty share of non-arm's-length bitumen. Indeed, a 2008 agreement between the province and oil sands operators summarizes the point (Alberta Energy 2008c).[5] In essence, the goal is to resemble a market-based price had the bitumen instead been sold to a third party. This process is inherently difficult, and has resulted in projects subject to the BVM being assigned revenues different from their non-BVM counterparts, all else equal. Since royalties are charged as a percentage of either gross or net revenues – in the case of sites subject to BVM, deemed revenues – this translates to projects subject to the BVM paying more royalties than they would have had they instead sold to a third party. A simplified breakdown of the BVM and its various components used to approximate a fair price for cleaned crude bitumen is described in Box 2.

5 The Syncrude Royalty Amending Agreement of November 2008, section 3(e), states the "BVM is not intended to competitively disadvantage the Lessees as a result of the application of a methodology that results in a higher value being attributed to Bitumen recovered from the Syncrude Royalty Project relative to the Projects of non-Integrated Producers."

Box 2: Understanding the BVM Framework

The approximate bitumen price in the Bitumen Valuation Methodology Regulations is calculated via the Hardisty Bitumen Price (HBP) calculation. The HBP is calculated within a hypothetical setting by which Alberta Energy assumes the cleaned crude bitumen for each project is blended with a standard diluent and transported and sold into the Western Canadian Select (WCS) pool at WCS Hardisty prices. Bitumen must be blended with a thinning agent, or diluent, to transport via pipeline. In market transactions, blended bitumen is the product exchanged, not bitumen alone.

The HBP for a project, for a month, is the greater of either the floor price or the following formula, simplified for illustrative purposes:

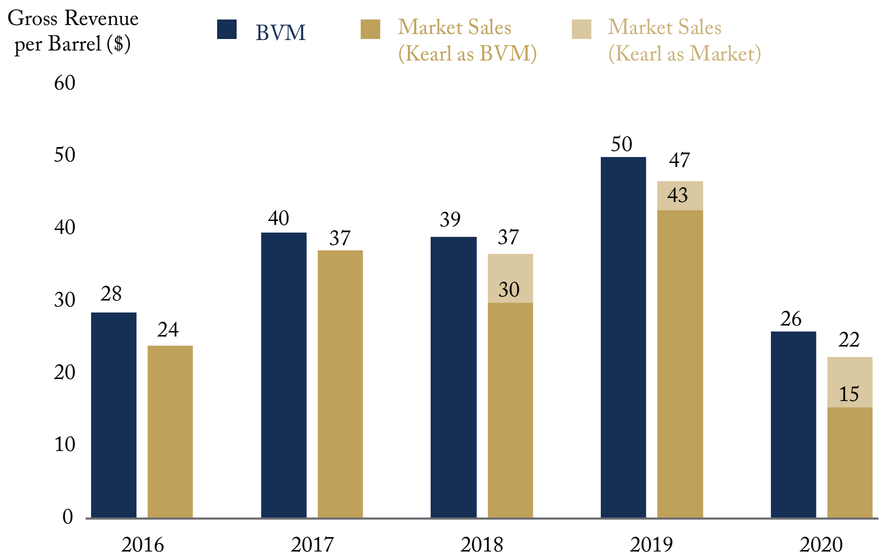
HBP = Blended Bitumen Price – Diluent Cost – Quality Adjustment.

The Blended Bitumen Price is based on the market price for WCS crude at Hardisty (itself comprising several heavy oil streams, including diluted bitumen); the Diluent Cost is based on market prices for condensate used to dilute bitumen; and the quality adjustment (QA) is currently set at the equivalent of $0.69 per barrel. The QA is set to expire at the end of 2021, and was introduced as part of the 2015 royalty review to account for assumed slightly lower refining value in oil sands – blended bitumen compared with WCS. A transportation allowance is then calculated for each project on a monthly basis. The allowance "nets back" the HBP to each project-specific royalty calculation point.

We note that the formula(s) specified in the BVM Regulations are far more detailed, and take into consideration a number of factors, such as the price of WTI, required volume of diluent, condensate allowance, a fluctuating price floor, and more, but the above equation suffices for explanation purposes. For more details, see Alberta Energy (2008a).

Commercial confidentiality considerations limit detailed available public data. This can make it difficult to determine the exact amount by which BVM valuations differ from non-BVM; in the public data, a project need only be designated as BVM-paying in one month out of the year to show as BVM-paying for the year. Most BVM-designated production is intended for affiliated upgrading destinations. In contrast, the Kearl mine, owned by Imperial Oil and ExxonMobil Canada, has operational flexibility and can send diluted bitumen either to affiliated facilities, in which case BVM determines royalty value, or sell it to third parties, in which case sales prices determine the value. Not knowing the exact volume breakdown in a particular year, we allocate Kearl into two cases: as either 100 percent BVM or as 100 percent third-party sales ("market") in 2018, 2019, and 2020, since the data show BVM was applied in those years. Using these two end-points provides a sense of the range of the difference.

Figure 2: Mined Oil Sands Production, BVM versus Market Sales, 2016–20



Notes: Volumes will be overstated for production subject to the BVM, and understated for production sold in the open market. The designation of Kearl as BVM or Market does not change BVM gross revenue per barrel when rounded to the nearest dollar owing to its relatively low volume compared to total BVM volumes.

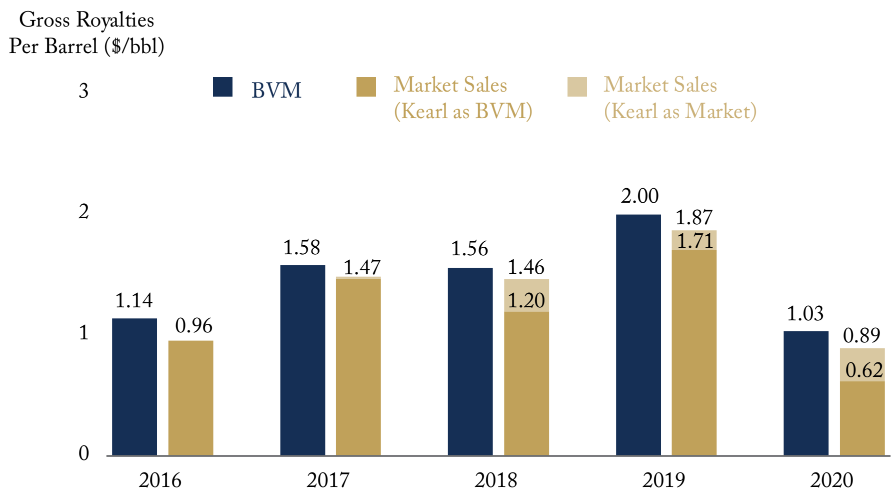
Sources: Authors' calculations from Government of Alberta (2021) and Alberta Oil Sands Royalty Data.

One would expect the value, and therefore the price, of bitumen for mining projects within a region to be highly comparable given similar geological endowments. All oil sands mines are located in the Athabasca area. Between 2016 and 2020, however, BVM mining projects were assessed as receiving a higher price than their non-BVM counterparts in every year. Depending on whether Kearl is designated as BVM-paying or not, this difference ranged between $3 and $11 per barrel of bitumen. If we exclude 2020 from the range to account for COVID-19's potentially disparate demand impacts on projects, the range was $3 to $9 per barrel. Even if we exclude 2020, it seems clear there is a difference between the prices used for projects paying royalties on BVM and those that do not.

All else being equal, a higher gross revenue per barrel will lead to a higher royalty paid. To illustrate this, we use a hypothetical scenario to calculate royalties paid where we assume that all oil sands mines in pre-payout status pay the same 4 percent gross royalty rate on their gross revenues.[6] We calculated hypothetical royalties

6 In reality, some projects are in pre-payout while others are in post-payout. This might lead some projects to pay a gross revenue royalty rate while others pay a net revenue royalty rate. Additionally, royalties are paid monthly such that, by year-end, the average royalty rate paid for each project might differ due to variations in their production and royalty rate in different months. For a simplistic example, we assume all mines are in the pre-payout stage and pay the same gross revenue royalty rate across the entire year.

Figure 3: A Royalties-per-Barrel Scenario for Oil Sands Mines, 2016–20



* This scenario assumes all mines pay an average gross royalty rate of 4% for consistency. In reality, this is not the case. Some mines are in post-payout and pay a net revenue royalty rate instead of a gross royalty rate. Additionally, royalty rates differ by month such that average annual royalty rates are production-weighted. This scenario is an illustrative example to show the effects of BVM on royalties paid. Note: BVM royalties per barrels do not change materially whether Kearl is included in BVM or Market, owing to Kearl's low relative volume.

Sources: Authors' calculations from Government of Alberta (2021) and Alberta Oil Sands Royalty Data.

per barrel, which would be the case if projects were at the same royalty stage, and find that they would have been higher for each year between 2016 and 2020 for oil sands mines subject to the BVM than those not (Figure 3).

If we include all volumes from the Kearl mine in third-party sales, these higher royalties would have amounted to between 8 and 18 cents per barrel, which averages out to a 9 percent increase in royalties due over the course of five years. Over this period, if all oil sands mines had been subject to the BVM and paid a gross royalty, they would have paid $245 million more at the higher BVM prices than if their per barrel revenues had been equivalent to those of non-BVM mines. If we include the Kearl volumes as paying BVM, royalties would have been greater by 11 to 41 cents per barrel, and producers subject to BVM would have paid $561 million more in royalties.

Quality differences between BVM and non-BVM oil sands production, to the extent they exist, are driven primarily by regional variation rather than by production method – although there is some difference in cleaned crude bitumen and blend quality arising from differences in processing technology. Bitumen quality is highly similar within each producing region: Athabasca, which represents the bulk of oil sands production, Cold Lake and Peace River.

Western Canada Select as a Benchmark

As described, the BVM formula adopts Western Canada Select, a grade of heavy crude oil, as its benchmark for use in royalty calculations. When selected over a decade ago, WCS represented the most widely traded and liquid market for western Canadian heavy crude oil. It has never been a perfect proxy for diluted oil sands bitumen from a quality or value perspective, containing not only bitumen from the oil sands but conventionally produced heavy oil from other geographies and formations.

Several oil sands blends now trade regularly in liquid markets, enabling greater price discovery between buyers and sellers. Blends such as Access Western Blend, Borealis Heavy Blend, and Christina Lake Dilbit are just a few dilbit blends available on the market. These blends typically have a Total Acid Number, a measure of corrosiveness, higher than that of WCS. Although public price data are limited (trading platforms typically reserve detailed price history for clients), these blends almost always fetch lower market prices than WCS. A higher WCS price than the true market value of oil sands blends means a company that is paying royalties based on WCS will pay more than its otherwise identical competitor that relies on third party transactions.

The BVM Floor Price Provision

The BVM regulation features an additional complication: the floor price, the price beneath which the calculated BVM price cannot fall. The floor price provision was put in place in the early days of oil sands market development, ostensibly to protect Albertans from situations with poor or inaccurate market-based price setting and discovery, such as potential regional price dislocations or even anti-competitive behaviour. If the calculated BVM price falls beneath the floor price, the regulation applies the floor price to producers' output. The floor price for a month is the greater of $10 per cubic metre ($1.59 per barrel) and a complex formula involving international crude benchmarks WTI and Brent, as well as Mexican Maya crude oil. Mexican Maya itself is based on a cocktail of benchmarks plus a "K" factor set arbitrarily by Pemex, Mexico's state-owned oil company.

When binding, the floor price further exacerbates the difference between non-BVM and BVM reference prices. Disruptions between Canadian and reference prices in 2018 and 2020 meant that the floor price applied to BVM at times, likely further widening the gap between BVM and non-BVM prices.

The existence of a floor-price provision in calculating royalties serves little purpose in the current era, when millions of barrels of oil sands crude are traded daily between many buyers and sellers and prices are visible to all participants. Influence from a non-transparent adjustment factor set by a foreign government-controlled entity adds an additional layer of separation from the Canadian oil sands market.

The Investment Disincentive and Horizontal Equity

To the extent that the BVM price is greater than the market price, assuming no quality or other differences, the royalty burden falls heavier on investments subject to the BVM. Some might argue that extra royalty take is acceptable from a strictly practical perspective: for existing oil sands investments the difference is not likely large enough to change the decision about whether or not to produce, so why not just collect more on behalf of Albertans? This view is, however, short-sighted, as several negative effects can arise from BVM prices that are too high.

Any difference in royalty treatment tilts the investment incentive away from activities that are at non-market prices, such as upgrading or refining. Royalties, by definition, are paid on the primary product produced (cleaned crude bitumen); secondary and tertiary processing considerations are separate, and should not be biased by royalty treatment. The global crude oil system is dynamic, continually responding to changes in supply and demand. Companies are closing refineries in some continents and countries, opening them in others, and retrofitting still others. Closer to home, Trans Mountain's planned pipeline expansion to the west coast of Canada will open new waterborne crude oil markets. The dynamic nature of crude oil demand means that sellers must adapt to meet that demand. A royalty system that does not favour one type of technology over another would allow the flexibility needed to make those necessary investments.

Those arguing against BVM reform sometimes point to the impressive investments made in upgrading and refining facilities under the BVM regime. Those investments are indeed impressive, but they might not have been optimal. Counterfactuals, by definition, are impossible to prove, but had a different system been in place, perhaps still more investment might have taken place. Obviously, the royalty regime is only one of many factors involved in making an investment decision: the BVM might not be the single largest factor, but it might be sufficient to make the marginal difference on a decision.

Horizontal equity posits that investments and companies ought to be treated similarly by fiscal and regulatory authorities. This basic principle underlies Canadian law and a basic sense of fairness. Horizontal equity means that companies should choose to invest in (or cease) production, refining, or upgrading activity based on economics, not policy design. Investment decisions altered by policy decisions not based on economic principles result in an economic deadweight loss, which policymakers should avoid.

Policy Recommendations

The Alberta government, like most authorities regulating natural resources extraction, regularly reviews its royalty regime. The most recent change became effective in January 2017. While the change affected primarily conventional oil royalty regulation – the oil sands royalty regime was not materially changed – one important outcome was that project-by-project oil sands royalty data became public. This added transparency improved the ability of Albertans, the resource owners, to better understand the royalties collected on their behalf. The change also introduced a $0.69 per barrel quality adjustment in the BVM formula, which was intended to address observed differences between market prices for bitumen blend and prices for non-market transactions, although the actual amount of the discount was ad hoc. The discount originally was set to expire at the end of 2019, but was later extended to the end of 2021 in anticipation of further work on the matter. Rather than implementing another ad hoc quality discount with uncertain expiry, Alberta should take this opportunity to substantively address the issue with a permanent, market-based solution.

We recommend that the Alberta government take meaningful steps to replace the BVM, including the floor-price provision, with bitumen prices calculated from actual third-party market sales. The difference in valuations on bitumen subject or not to BVM creates a distortion between projects affected by it and those that are not. To minimize this distortion between third-party and non-third-party transactions, the price upon which royalties are based should be the same, all else being equal.

Millions of barrels per day of oil sands crude are sold to third parties. Prices for several blends are tracked by reporting agencies; most important, all sales revenues and transport costs must be reported to Alberta's royalty department to allow it to calculate royalties for those volumes. This forms a solid foundation of data on which to value other, non-third-party-traded volumes.

The Alberta government can easily calculate the regional weighted-average price per barrel of third-party sales. Accordingly, the BVM regulation should be replaced with a system that relies on actual third-party sales and transportation data, already collected by the government, to calculate a market-based Hardisty bitumen price. Aggregated data underlying the calculation ought to be published publicly, alongside existing oil sands royalty data. Accounting for quality differences between regions would be relatively simple given that bitumen, unlike conventional crude oil, is highly similar within regions. This could be backstopped by a weighted-average, market-based basket of high Total Acid Number bitumen blends, which would represent a ceiling price with which to replace WCS in the BVM calculation; appropriate adjustments would need to be made to deemed diluent blend ratios as well.

While detailed calculations and wording of the regulation obviously should be the work of the Alberta government, in consultation with stakeholders, we recommend that no additional quality adjustments be included. Doing so would only perpetuate the lengthy cycle of industry-government negotiation and undermine the principles of clarity, simplicity and market-determined pricing.

At the same time, the Alberta government should eliminate the floor-price provision. The provision exacerbates differences between BVM and non-BVM payers. Further, the royalty formulas for all other natural resources production in Alberta contain no similar distortionary provisions, and their existence cannot be justified by any substantive economic argument.

The government originally intended the BVM to protect Albertans' interests in the absence of market prices at the beginning of a new industry. The situation has changed, and the market has matured. Eliminating the BVM would align with the principles set out for amending royalty regimes in agreements such as that with Syncrude, for example (Alberta Energy 2008c). The reference price in that agreement was to be based on "one or more liquid, transparent, arm's-length Canadian heavy oil markets…with adjustments to recognize differences in quality between the product represented by the selected market and the Bitumen from each particular source of Bitumen subject to the Crown royalty, and adjustments to recognize transportation and handling costs of Bitumen and diluent." The agreement reserved the government's right to use a higher price only if there was "a temporary disconnect between Canadian heavy oil and North American heavy oil market prices."

In the amending agreement, any potential BVM adjustments were to be temporary; it is past time for a permanent solution. Given the impressive development of the Canadian oil sands industry, its mature status in meeting global demand and the large number of buyers and sellers in the global oil industry, it is time to base non-arm's-length transaction prices for oil sands royalties on market-based mechanisms.

Governments are right to want each producer to pay the correct amount. They are also right to ensure that each producer pays the same amount as its competitors, all else being equal. Globally, fiscal authorities overseeing many integrated industries have had concerns about the incentive for potential misreporting. There is no evidence for this in the oil sands, but if it is indeed a concern, evidence ought to be disclosed and dealt with directly in the appropriate domain.

Eliminating the Bitumen Valuation Methodology in favour of a market-based solution would improve royalty equity between project types, increase transparency, eliminate the distortionary floor price, improve incentives for investment and reduce administrative burden.

Conclusion

Alberta's oil sands investments contribute substantially to the province's and Canada's economy. A stable and competitive oil sands royalty regime would support long-term investment. Such a regime should be horizontally equal – in other words, it should treat all investments equally from a royalty perspective. Equity underpins optimal investment and promotes investment confidence.

The Bitumen Valuation Methodology that the Alberta government uses to value bitumen production for royalty purposes has consistently overvalued that production, compared with market-determined values, by between $3 and $11 per barrel in recent years, thereby increasing calculated royalties for those producers. With well over a million barrels per day of oil sands crude oil sold at market prices, the impressive maturation of the oil sands market now provides clear price discovery.

In light of this misalignment, the Alberta government should re-examine the BVM. Specifically, it should replace the current calculation with actual third-party sales data to calculate a regional proxy by which to value non-traded products, and remove the floor-price provision, which further exacerbates potential royalty differences between BVM and non-BVM volumes. As a backstop, the government could consider using a basket of oil sands – specific diluent blends as a price input, the prices of which are now easily available.

These changes alone would not guarantee increased oil sands investment, but they would improve the fair and efficient allocation of future investment in oil sands extraction and subsequent processing and transport activities.

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