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ALBERTA'S NEW ROYALTY REGIME IS A STEP TOWARDS COMPETITIVENESS: A 2016 UPDATE

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SUMMARY

Alberta's new royalty regime has made the province a more rewarding place for anyone looking to invest in conventional non-renewable resources. After Alberta's NDP government commissioned a review of the royalty regime to ensure the province was receiving its "fair share," it ended up determining that revenue-neutral changes were warranted to the royalty system for conventional oil, with oilsands largely left untouched. However, the few changes that were made have had a substantial impact on incentives for new investment. Those changes have, in fact, only made it more lucrative for investors in Alberta's conventional oil and gas.

This paper focuses on oil and the fiscal regime (it does not consider other regulatory and carbon policies that affect competitiveness). The changes for conventional oil are significant enough that the new regime entirely overcomes the competitive disadvantages for non-oil sands producers created by the NDP government's increase in provincial corporate income taxes last year.

Under the current regime, Alberta conventional oil bears a marginal effective tax and royalty rate (METRR) of 35.0 per cent (the METRR is relevant for new investment decisions). The changes have sharply reduced that to 26.7 per cent. This year, when compared against its peers in the U.S., Europe and Australia, Alberta has one of the highest METRRs for conventional oil. When the new royalty regime takes fully effect in 2017, it will have one of the lowest, bested only by Australia, the United Kingdom, Pennsylvania and, in Canada, Nova Scotia and Newfoundland & Labrador. Most notably, Alberta is more competitive now than its immediate neighbours, British Columbia and Saskatchewan, for conventional oil investment. It is also less distorting across different types of wells, which is an important quality in a well-designed royalty system.

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Alberta continues to implement a system of price-sensitive royalty rates with the government's take increasing with the oil price. Our results are derived using a certain projected oil price and a certain projected exchange rate — in this case US$50 per barrel of West Texas Intermediate and 77 U.S. cents per dollar — with changes to either potentially altering the rankings and making Alberta more or less competitive, depending on what happens with those two variables. Under the new regime, Alberta's tax burden on conventional oil projects is reduced for a wide range of oil prices. Whether the Province will attract investment for conventional oil once the market conditions improve will depend as well on other policies being adopted but at least the new royalty regime will help boost interest in the Province.

With the Alberta government having completed its review of its royalty regime, the degree to which its fiscal regime discourages or attracts investment relative to other options for oil investments remains of significant interest to the public. Certainly, with low global oil prices, investment is being severely cut back around the world at this time. However, interest in petroleum investments will improve globally when prices firm up, so Alberta's fiscal regime will be a critical element in determining how much new investment the province attracts. This report specifically examines corporate taxes and royalties although competitiveness can also be affected by regulations and carbon policies that are not subjects of this analysis.

Looking at the fiscal impacts on new investment, we show below that Alberta's previous fiscal regime prior to the recent reform was not particularly competitive in attracting investment relative to some jurisdictions, but neither was it badly out of line with other jurisdictions considered in this study, a result consistent with the conclusions of the province's own royalty review.[1] However, the new Alberta royalty regime improves sharply the competitiveness of the fiscal regime for conventional petroleum (the oilsands royalty regime changed little), overcoming the increase in the provincial corporate income tax rates in 2015. Alberta's fiscal regime is still less competitive when compared to Australia's, the United Kingdom's and the Atlantic offshore regimes, but it is more attractive than regimes in the United States (except in Pennsylvania), Saskatchewan and, to a lesser degree, British Columbia.

We also find that the new royalty regime in Newfoundland & Labrador reduces distortions while maintaining competitiveness with most royalty regimes.

Much of the concern over royalty design has focused on "fair" share. However, a well-designed royalty system would follow three general principles:

- As owner of the resource, the province is entitled to a significant share of rents.
- To attract the best producers, the province should design a royalty system that provides stability and a competitive rate of return consistent with other jurisdictions. This implies that the ablest producers will receive some share of rents.[2]
- The royalty should distort investment decisions as little as possible in order to maximize rents earned on projects.

Our analysis, focusing on investment effects, does not provide guidance as to whether Alberta collects its "fair" share of rents (rents being the difference between revenues and all operating and capital costs incurred to produce oil). Recent work by Duanjie Chen shows that Alberta has historically collected roughly 50 per cent of rents through its royalty from conventional[3] oil and gas production and more than 100 per cent of rents from oilsands production (many new investments have not reached maturity in generating profits yet and, given current oil prices, will take some

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1 Canada. Government of Alberta, *Alberta at a Crossroads*, Royalty Review Panel Report (Edmonton, Alberta 2016).

2 See Jean-Jacques Laffont and David Martimort, *The Theory of Incentives: The Principal-Agent Model* (Princeton, New Jersey: Princeton University Press, 2002). The application of the principal-agent model to royalty design is discussed further in J. Mintz, "Taxes, resources and cross-border investments," in *International Taxation and Extractive Industries,* ed. by P. Daniel, M. Keen, A. Swistak and V. Thuronyi, Routlege, forthcoming in 2016.

3 In this paper we distinguish between oilsands (bitumen) and conventional production in Alberta. Conventional oil, including shale, is recoverable at a well from an underground reservoir and is liquid at atmospheric pressure and temperature. See Canada Government of Alberta website, "Conventional crude oil and oil sands," http://www.albertacanada.com/business/industries/og-conventional-crude-oil-and-oil-sands.aspx.

time before new projects earn rents).[4] Alberta also collects a share of rents through the corporate income tax and other levies on capital investments, such as property taxes.[5]

The existing taxes and royalties do impose distortions on investments, impairing economic efficiency and therefore reducing rents earned by the government and producers. And even though the new Alberta royalty proposals will reduce distortions, they will not successfully achieve all the aims of optimal royalty design.

In this short paper, we present an update looking at the impact of oil fiscal regimes in various jurisdictions on the incentive to invest in upstream oil projects. In 2012, The School of Public Policy published a comparative study[6] of marginal effective tax and royalty rates for Canada, the United States and several other major oil producers around the world. Four years later, the market for oil has witnessed substantial changes, in particular the collapse of world oil prices since the second half of 2015. With some jurisdictions tying their royalties to the price of oil, and others amending their royalty rates and other tax policies, it would be interesting to know how the effective tax rates on oil and gas compare with competing countries and, in particular, where Canadian provinces stand today.

MARGINAL EFFECTIVE TAX AND ROYALTY RATES

The analysis below is based on a time-to-build model in which exploration and development expenditures are undertaken to prepare reserves for extraction. Conceptually, a business invests in capital (exploration, development and post-production capital) until the rate of return on incremental dollars is equal to the cost of capital (at this point, no further rents are earned). To measure the effect of taxes and royalties on investment decisions, the marginal effective tax and royalty rate (METRR) is calculated as the amount of taxes and royalties paid as a percentage of the pre-tax-and-royalty, net-of-risk return on capital that would be required to cover taxes, royalties, and the financing of capital with debt and equity.[7]

The advantage of this approach is that the variation in METRR across assets and industries provides a basis for analyzing capital distortions in fiscal systems. The higher the METRR, the lower investment will be, since the tax-adjusted cost of capital is higher, squeezing out marginal projects in an industry. Similarly, if one type of asset is favoured over others, companies will have an incentive to shift expenditures from one type or form to another and therefore impact on the technical choices made by firms in developing extractive projects. For example, fiscal systems typically provide incentives for exploration and development; it is not inconceivable that firms will push capital expenditure into the exploration or development phase that would have taken place post-production, thereby raising the overall cost of production.

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4 Duanjie Chen, "Alberta Gets 51% in Royalties: Is that Fair?' *Financial Post*, January 29, 2016.

5 The new carbon tax in Alberta is not included in this analysis since it is a tax unrelated to capital investment (the carbon tax does raise the cost of production and consumer fuel prices). To analyze output-related taxes, a different analysis would be required that is inclusive of other taxes affecting all inputs used in production.

6 J. Mintz and D. Chen, "Capturing Economic Rents from Resources through Royalties and Taxes," University of Calgary, School of Public Policy Research Paper 30 (2012). We will not repeat the theoretical and methodological explanation provided in the earlier paper.

7 Risk is incorporated in the analysis by measuring the risk-adjusted rate of return on capital. To the extent that the tax or royalty system shares risks with the producers by allowing for the refundability of losses, the government provides an implicit deduction for the cost of risk. This proposition is well-known in the economic literature, and it implies that the risk premium from capital-asset pricing models is reduced by the factor one minus the tax rate (see J. Mintz, "The Corporation Tax: A Survey," *Fiscal Studies* 16, 4 (1996): 23-68).

METHODOLOGY

With the exception of Alberta and Newfoundland & Labrador,[8] the other jurisdictions considered here have either kept their tax treatment of the oil sector unchanged or have undertaken relatively minor changes in their royalty or corporate tax provisions. We therefore use the same theoretical model derived in the 2012 study, while updating the tax and non-tax parameters to current values. We have also remodelled Newfoundland & Labrador to take into account its new generic royalty regime, which is quite different than the previous regime.

We have updated the baseline oil price to US$50 per barrel to reflect the current market conditions and long-term expectations. We have also updated the operating cost per barrel of oil to US$10 per barrel based on recent estimates by the Canadian Energy Research Institute.[9] We also provide some sensitivity estimates for various oil price levels ranging from US$30 to US$70 (West Texas Intermediate) and for changes in operating cost of up to 20 per cent.

For all countries, we use updated inflation rates calculated as 10-year average (2004–2014) GDP-deflator inflation rates based on OECD data, which range from 1.20 per cent in the United Kingdom to 3.88 per cent in Norway. We have also updated the real interest rate and use the same rate of three per cent for all countries, which is in line with long-term average interest rates and a standard figure used in the economic literature. We have changed the time-to-build period for the development of oil projects from a two-year period to a more realistic six-year period (the expenditures made during the period are fixed per year, so the midpoint of development expenditures takes place three years before extraction begins).

In addition, we have updated for each country the tax and non-tax parameters affecting the marginal effective tax rates mainly based on information available in the Ernst and Young "Global Oil and Tax Guide 2015" and governmental websites. These changes are outlined below, alongside the main features of the tax treatment of oil and gas activities.

WHAT FISCAL CHANGES HAVE HAPPENED SINCE 2012?

Australia

The Australian government has made no major changes in its fiscal treatment of oil and gas activities since 2012. Some changes that do not affect our model include the repealing of the carbon pricing legislation implementing the carbon pricing mechanism on July 17, 2014, as well as an extension of the petroleum resource rent tax (which previously applied to offshore projects only) to onshore projects and the North West Shelf project beginning July 1, 2012. The main elements of the Australian fiscal system for oil activities include: a corporate income tax of 30 per cent; royalties ranging from 10 to 12.5 per cent for onshore projects administered at state level; the petroleum resource rent tax (PRRT) of 40 per cent, deductible for income tax purposes and administered federally; as well as a system of capital allowance provisions and investment incentives. Under PRRT, expenditures that exceed revenues can be carried forward at an uplift rate ranging from the long-term bond rate plus five percentage points (for general expenditures), to the long-term bond

[8] The government of Newfoundland & Labrador announced the introduction of a new, generic royalty system on Nov. 2, 2015 to replace bilateral negotiations with investors. Details can be found on the government website at: http://www.nr.gov.nl.ca/nr/royalties/generic_regime.html.

[9] Julie Dalzell, "Conventional Oil Supply Costs in Western Canada," Canadian Energy Research Institute Study No. 135 (Calgary, Alberta: CERI, June 2013).

rate plus 15 percentage points (for exploration expenditures).[10] The results included in this report reflect the offshore sector only.

Canada

Since 2012, the federal government has reduced some important tax incentives for the oil sector. These include the phasing out after 2016 of the accelerated depreciation allowance of up to 100 per cent for new mine or mine-expansion assets (certain oil and gas projects are affected by this provision), and the phasing out of the Atlantic Investment Tax Credit fully by the end of 2015.[11]

There have also been some fiscal changes at the provincial level.

- Alberta increased the corporate income tax rate from 10 to 12 per cent effective July 1, 2015. The royalty rates for both conventional oil and oilsands have decreased automatically due to the decrease in the price of oil. As discussed, Alberta has announced a new royalty regime slated for adoption in 2017, which is discussed in the next section.[12]
- British Columbia increased its corporate tax rate effective April 1, 2013 from 10 to 11 per cent. In 2013, British Columbia reinstated the retail sales tax after the Harmonized Sales Tax, implemented in 2010, was rejected by a referendum. This has a significant impact in the resource sector by increasing taxes on capital purchases.
- Saskatchewan made no change to its tax rates, but the royalty rate for oil has decreased as a result of the formula that is sensitive to the price of oil. The corporate income tax rate remains at 12 per cent.
- In Nova Scotia, there have been no specific changes outside of the changes to the federal Atlantic Investment Tax Credit as mentioned above. The corporate income tax rate is 16 per cent.
- Newfoundland & Labrador introduced a new, generic offshore-oil royalty regime in November 2015 based on the R-factor approach (revenue over accumulated cost index). The system includes a basic royalty rate ranging from one to 7.5 per cent applied to gross revenue as the project starts producing oil, increasing as the project recovers more of its costs. After costs have been recovered, a net royalty ranging from 10 per cent to 50 per cent will be applied to net revenue varying by the R-factor, and the basic royalty becomes a credit against net royalties. We have modelled these changes in the analysis below by assuming that the marginal investment reaches the maximum profitability (R-factor above three) so that the effective royalty rate is 50 per cent.[13] In addition to the royalty change, Newfoundland & Labrador raised its corporate income tax rate from 14 to 15 per cent effective Jan. 1, 2016.

Norway

Companies involved in extractive activities in Norway are subject to a corporate income tax of 27 per cent, as well as a special tax or resource-rent tax in the offshore sector of 51 per cent (none

[10] Deloitte, "Oil and Gas Taxation in Australia," *Deloitte Taxation and Investment Guides* (2013), http://www2.deloitte.com/content/dam/Deloitte/global/Documents/Energy-and-Resources/gx-er-oilandgas-australia.pdf.

[11] The Atlantic Investment Tax Credit was equal to 10 per cent until 2013. It was decreased to five per cent in 2014 and 2015, and was completely eliminated in 2016.

[12] The Alberta government announced in July 2016 that companies can adopt the new regime early, in 2016, if they so desire.

[13] The intermediate case when the R-factor varies between one and three results in an incentive to expand the capital base to reduce the R-factor. This leads to a lower effective statutory tax rate that reduces the METRR calculated for investments. We are unable, however, to compute this case due to lack of data.

for onshore). These rates represent a slight change from 2012 when the corporate income tax was 28 per cent and the special tax was 50 per cent. Capital allowances for investment in facilities and installations are calculated on a straight-line basis over six years. For special purposes, an accelerated capital allowance is granted, which is spread over four years. Costs incurred before May 5, 2013 were subject to an annual uplift under the special tax of 7.5 per cent over a four-year period, which has been reduced to 5.5 per cent per year for expenditures incurred after May 4, 2013.[14]

The United Kingdom

The U.K. has a fiscal regime for the oil and gas industry that includes a corporate income tax and a supplementary charge, as well as capital allowance provisions and various investment incentives.[15] A series of changes have been adopted since 2012. The corporate income tax for non-ring-fence projects was reduced from 21 to 20 per cent starting April 1, 2015. The corporate income tax rate is still 30 per cent for ring-fence projects (the rate we use in our analysis). The summer budget of 2015 proposed that the corporate income tax for all profits except ring-fence profits be further reduced to 19 per cent for taxation years starting April 1, 2017, and reduced again to 18 per cent starting April 1, 2020 (the corporate rate is to be further reduced to 17 per cent as announced by the Chancellor of the Exchequer after the Brexit vote).[16] The supplementary charge was reduced from 32 to 20 per cent beginning Jan. 1, 2015, and then to 10 per cent in Budget 2016, backdated to Jan. 1, 2016. Companies that incur a ring-fence loss in a period, which they cannot offset against other ring-fenced taxable profits, may claim the Ring-Fence Expenditure Supplement, which increases the ring-fence losses carried forward by 10 per cent per year for a maximum of 10 years (increased from six years prior to Dec. 5, 2013.) The Finance Act of 2014 introduced an allowance for onshore oil and gas projects, which reduces the profits of each qualifying project that is subject to the supplementary charge by an amount equal to 75 per cent of the capital expenditure incurred on that project on or after Dec. 5, 2013. The results included in this report reflect the offshore sector only.

The United States

The United States applies a federal corporate income tax rate of 35 per cent, with a manufacturing deduction of six per cent that applies to the oil and gas sector, resulting in an effective corporate income tax rate of 32.9 per cent. Some states, but not all, levy a corporate income tax, which is deductible from the federal corporate income tax base.

- Arkansas and Colorado have not adopted any significant changes to their fiscal regimes for oil and gas since 2012. Arkansas still applies a corporate income tax of 6.5 per cent,[17] a royalty rate on oil extraction of one-eighth, or 12.5 per cent, and a severance tax of five per cent of the market value of oil (four per cent for wells producing less than 10 barrels per day). Colorado has a corporate income tax of 4.63 per cent, a royalty rate representing one-sixth of the gross sales value of oil or gas, and a severance tax of five per cent.[18]

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14 From "Oil and Gas Taxation in Norway," *Deloitte Taxation and Investment Guides* (2014), 3, http://www2.deloitte.com/content/dam/Deloitte/global/Documents/Energy-and-Resources/gx-er-oil-and-gas-taxguide-norway.pdf.

15 A petroleum revenue tax that applied to fields that received development consent prior to March 16, 1993 was reduced from 50 to 35 per cent beginning Jan. 1, 2016, and then effectively eliminated in the 2016 budget.

16 From United Kingdom. HM Revenue and Customs website, "Guidance- rates and allowances: Corporate Tax," https://www.gov.uk/government/publications/rates-and-allowances-corporation-tax/rates-and-allowances-corporation-tax.

17 For corporations with net taxable income exceeding US$100,000.

18 Applied to the total net gross income in excess of US$299,999.

- North Dakota is now the second-largest oil producer in United States, after Texas, and a new addition to our METRR study. There are two oil-specific taxes in North Dakota: the oil gross production tax and the oil extraction tax. In 2015, the extraction tax provisions were reformed in order to reduce fluctuations in tax revenues associated with fluctuations in oil prices. In particular, an old provision was dropped that decreased the extraction tax rate to zero for most wells if the price of oil stayed under US$55 per barrel for more than five months.[19] At the same time, the extraction tax rate has been reduced from 6.5 to five per cent beginning Jan. 1, 2016. However, the rate can increase to six per cent if the high-price trigger is in effect, i.e., if the average price of oil exceeds US$90 per barrel each month during a three-month period. Besides the oil extraction tax, there is a production tax of five per cent applied to the gross value at the well of all oil produced.[20] Overall, the maximum total tax rate is 10 to 11 per cent. North Dakota also has a royalty rate on public land of 18.75 per cent and a corporate income tax rate of 4.31 per cent.[21]
- Pennsylvania currently has no severance tax, but is debating whether to introduce one.[22] The corporate income tax is 9.99 per cent, the largest of all states considered. The royalty rate is one-eighth, or 12.5 per cent.[23] In February 2012, Pennsylvania introduced an impact fee on shale gas producers, a flat annual fee increasing each year and collected for a period of 15 years to compensate municipalities for the environmental impact of drilling activities. A corporate loan tax was eliminated in 2014, but corporations were still subject to a capital stock tax (for domestic firms) or foreign franchise tax (for foreign firms) at a rate of 0.45 mills of the corporation's capital stock in 2015. These taxes have gradually been phased out since 2012, and were completely eliminated for 2016.
- Texas applies a franchise or margins tax for the privilege of doing business in Texas. It has been reduced gradually from one per cent of a taxable entity's margin to 0.975 per cent in 2014, to 0.95 per cent in 2015, and is now permanently reduced to 0.75 per cent (as of 2016).[24] The royalty rate on public land is 25 per cent. Texas has a severance tax of 4.6 per cent on the market value of oil and condensate (the oil production tax), and 7.5 per cent on natural gas (the natural gas production tax). There is also an oilfield cleanup fee of 5/8 of a cent (US$0.00625) per barrel; this used to be supplemented by a regulatory fee of 3/16 of a cent (US$0.001875) per barrel, which was abolished starting on Sept. 1, 2015.

19 Mark Peters, "North Dakota Overhauls Tax on Oil Producers," *The Wall Street Journal*, April 30, 2015, http://www.wsj.com/articles/north-dakota-overhauls-tax-on-oil-producers-1430433385.

20 United States. Government of North Dakota website, "Oil & Gas Severance Tax," https://www.nd.gov/tax/oilgas/.

21 Applied to taxable income exceeding US$50,000.

22 Pennsylvania Governor Tom Wolf, a Democrat, proposed a severance tax on natural gas of five per cent plus a volumetric fee of 4.7 cents per thousand cubic feet in the summer of 2015. In a revised proposal, he later reduced the proposed severance tax to 3.5 per cent (plus the volumetric fee) due to difficulties in passing the budget through the Republican-controlled legislature. The 2015–16 budget took nine months to pass and the severance tax was not adopted. A new rate of 6.5 per cent was proposed in Feb. 2016. See Reid Frazier, "Wolf tweaks gas tax plan; GOP, industry unimpressed," *StateImpact*, October 16, 2015, https://stateimpact.npr.org/pennsylvania/2015/10/06/wolf-tweaks-gas-tax-plan-gop-industry-unimpressed/; and Jamison Cocklin, "Pennsylvania Governor's Severance Tax Proposal Could Set Highest Rate in Nation," *NGI's Shale Daily*, April 27, 2016, http://www.naturalgasintel.com/articles/106201-pennsylvania-governors-severance-tax-proposal-could-set-highest-rate-in-nation.

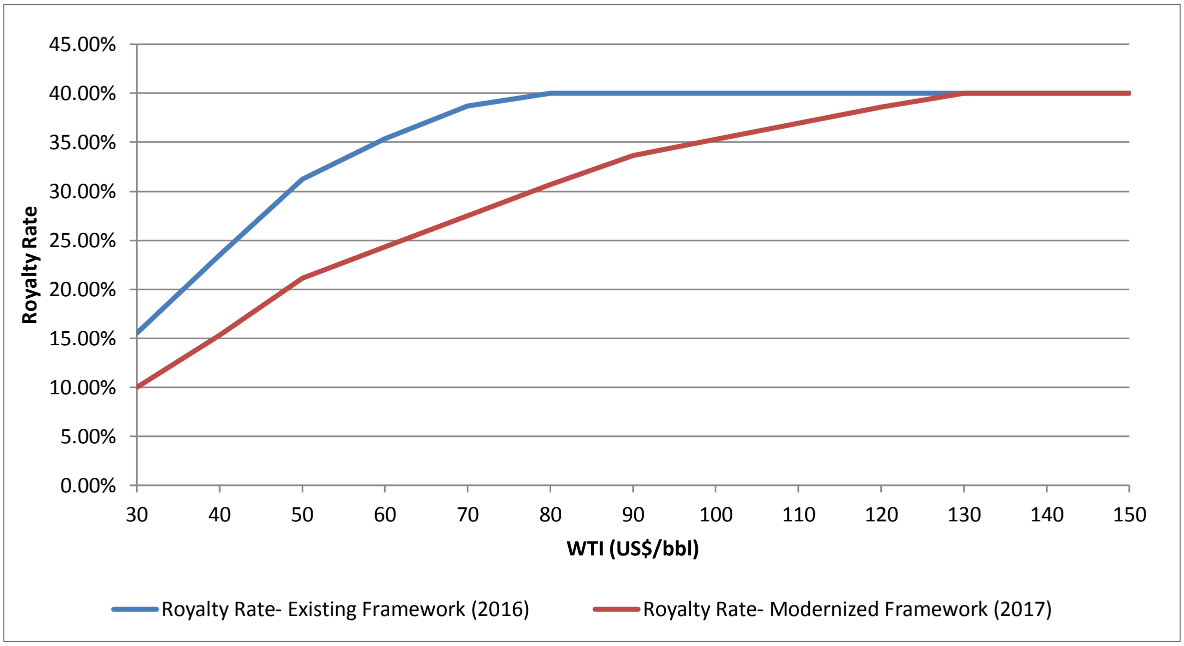
23 Section 1.9, added to the Pennsylvania's Guaranteed Minimum Royalty Act of 1979 on July 9, 2013, specifies that a lease contracts for oil and natural gas is only valid if the lessor is guaranteed at least one-eighth royalty of all oil or natural gas recovered.

24 The tax base can be calculated in several ways: total revenue times 70 per cent; total revenue minus cost of goods sold; total revenue minus compensation; or total revenue minus US$1 million (see United States. Government of Texas, Comptroller of Public Accounts website, "Franchise Tax Overview," http://comptroller.texas.gov/taxinfo/taxpubs/tx98_806.html.)

ALBERTA'S ROYALTY REVIEW: IMPACT ON COMPETITIVENESS

The recent Alberta royalty review did not lead to significant changes to the oilsands royalty regime but it did result in a new royalty structure for conventional oil and gas. Under the current regime, the royalty rate for conventional oil increases with price and well productivity. With the new regime, the royalty rate on sales will remain price-sensitive but unrelated to volume until a threshold is reached (royalty rates decline when production drops below 194 cubic metres per month or approximately 40 barrels per day). A cost recovery allowance, sensitive to well depth but otherwise based on industry experience, will be provided instead of various drilling incentives. The new system includes a consolidation of royalty rates for fuel types produced from a well, as well as a five per cent minimum royalty on sales until the cost allowance is used up. The new post-payout royalty rate has been announced: After recovery of the cost allowance, the new royalty rates are below the older rates for a wide range of price levels as shown in Figure 1.[25] Further, the government has also announced two new programs — the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program — that will provide an allowance for eligible costs with a corresponding royalty rate of five per cent. Once the cost allowance is used up, the new royalty rates will apply.

FIGURE 1 NEW AND EXISTING ROYALTY RATES FOR CONVENTIONAL OIL IN ALBERTA



We note that the cost allowance is independent of individual actions (it is based on industry-wide experience) and therefore results in the royalty structure having a similar impact as a revenue-based royalty regime, like that found in the United States and some other jurisdictions. In other words, while Alberta's new system is argued to be a revenue-over-cost model, each firm's cost is irrelevant to the determination of the royalty payment (the only firm-specific variable is well depth). While total royalty collections are expected to remain unchanged, the marginal royalty rate on production

[25] The royalty rates in Figure 1 correspond to a well producing 50 barrels of oil per day, but the results are similar for other production levels. The royalty rates under the existing regime equal or exceed those under the new regime whenever the oil price is above US$26 per barrel at the exchange rate of 77 U.S. cents per Canadian dollar, or the well productivity is above 49 barrels per day.

in excess of the cost allowance is reduced under the new scheme, resulting in a lower METRR as will be shown below for 2017.

The new Alberta royalty regime therefore generally improves the competitiveness of the industry by lowering royalty rates after the cost allowance is used up. The cost allowance based on industry data, the elimination of drilling incentives and the consolidation of rates is simpler and less distorting across well types. The two new incentive programs discussed above will further help projects with recovery costs and new development. As noted by the panel, any cost efficiencies achieved by producers will result in higher profits without increasing royalty payments. This could encourage innovation as well.

On the other hand, wells with above-average costs will have an inadequate cost allowance and will therefore have lower rents than wells with below-average costs. Given that the same royalty will be paid (all else being equal), lower-rent projects will pay more royalties as a share of rent compared to high-rent projects. Otherwise, only a resource levy based on an actual firm's revenues and costs would avoid differences in effective tax rates on rents across well types.

RESULTS

Taking into account the various corporate income tax provisions and royalties and the sales tax on capital purchases, tables 1 and 2 below provide the METRR results for each jurisdiction.

As shown below in Table 1, Alberta conventional oil currently bears an METRR of 35.0 per cent,[26] sharply reduced by the new royalty regime to 26.7 per cent.[27] While Alberta has one of the highest METRRs for conventional oil investments in 2016 among the jurisdictions in the study, the new royalty regime will reduce the effective tax and royalty burden on investment below all other jurisdictions except for Australia, the United Kingdom, Pennsylvania and the two Atlantic provinces.

Overall, conventional oil in most of the jurisdictions are subject to well-by-well revenue-based royalties that result in relatively high METRRs. A royalty based on production revenues paid on a well-by-well basis without an explicit deduction for costs raises the cost of undertaking investments in marginal projects, which earn no rent (a true rent-based royalty would be zero for marginal investments since revenues just cover the economic costs of production). Thus, for marginal projects that earn no rent, the Alberta conventional royalty reduces the return on investment and therefore discourages investments in marginal projects.

On the other hand, the oilsands royalty system, for which METRR is 29.3 per cent (Table 1), generally applies to rents by allowing a deduction for costs. It therefore discourages investment in the oilsands to a lesser extent compared to the current regime for conventional oil in Alberta, but will be a higher tax burden on capital compared to conventional oil under the new regime in 2017.

Oilsands investment bears a relatively high METRR since the rent-based royalty interacts with the burden of the corporate income tax on marginal investments. When no corporate income taxes are paid, the royalty burden is small at only 0.3 per cent (Table 2, column C). A rent-based royalty in the absence of corporate income taxes typically yields an METRR of zero. The small but positive

26 For a well producing 50 barrels of oil per day, our benchmark case.

27 The Alberta corporate tax rate increase from 10 to 12 per cent in 2015 raised the METRR from 34.3 to 35 per cent for conventional oil, while the new royalty regime reduces it to 26.7 per cent.

METRR for oilsands in the absence of the corporate income tax reflects the payment of a revenue-based royalty before costs are fully deducted from accumulated net revenues.[28]

TABLE 1 MARGINAL EFFECTIVE TAX AND ROYALTY RATE BY JURISDICTION (IN PER CENT), 2016

	Exploration	Development	Depreciable	Inventory	Aggregate
	(A)	(B)	(C)	(D)	(E)
Canada*	**13.8**	**18.8**	**31.7**	**30.8**	**27.7**
British Columbia*	24.3	28.1	32.9	25.7	**28.7**
Alberta					
Conventional** (2016)	38.5	41.7	25.3	26.6	**35.0**
Conventional** (2017)	25.2	29.1	25.3	26.6	**26.7**
Oilsands	-1.0	5.5	34.5	34.6	**29.3**
Saskatchewan**	28.4	32.2	36.7	27.9	**32.6**
Newfoundland & Labrador	-2.9	3.8	50.1	N/A	**11.8**
Nova Scotia	-6.1	-18.8	36.4	N/A	**-3.5**
U.S.	**36.3**	**37.1**	**35.5**	**24.6**	**36.1**
Arkansas	23.8	24.9	39.3	27.1	**29.5**
Colorado	28.4	29.4	36.5	26.1	**31.5**
North Dakota	35.7	36.6	35.4	25.9	**35.7**
Pennsylvania	18.8	20.0	38.0	29.1	**25.9**
Texas	37.4	38.2	35.4	23.9	**36.7**
Australia	-146.3	3.2	17.6	N/A	**-35.5**
Norway	-3.7	30.1	82.9	N/A	**31.9**
United Kingdom	-2.5	-1.5	-4.8	N/A	**-2.5**

Source: Authors' calculations.

* Canada average METRR reflects the new royalty regime in Alberta (2017). With the existing Alberta royalty regime, the Canada-wide METRR would be 30.9 per cent.

** The royalty rates, and hence the marginal effective tax rates, for British Columbia, Alberta conventional oil and Saskatchewan are contingent on well productivity. In this table, we assume a well producing 50 barrels of oil per day for all three provinces. For a lower-productivity well with an output of 30 barrels per day, the aggregate METRR would be 23.3 per cent in British Columbia, 28.2 per cent in Alberta under the current regime and 21.3 per cent under the modernized regime, and 27.1 per cent in Saskatchewan. For a higher-productivity well with an output of 80 barrels per day, the METRRs would increase to 31.7 per cent in British Columbia, 40.6 per cent in Alberta under the current regime and 26.7 per cent under the modernized regime, and 35.7 per cent in Saskatchewan. One of the recommendations of Alberta's royalty review panel was indeed to flatten the royalty rate schedule across different-sized wells.

[28] Intuitively, a rent-based royalty shares profits and risks with investors, but does not share the corporate tax burden. See J. Mintz, "Taxes, Royalties and Cross-Border Investments," in *International Taxation and the Extractive Industries*, ed. P. Daniel et al. (Washington D. C.: International Monetary Fund, Routledge, forthcoming 2016).

TABLE 2 DECOMPOSING THE METRR ON NEW INVESTMENT (IN PER CENT), 2016

	All Levies	Taxes Only	Royalty Levies Only
	(A)	(B)	(C)
Canada*	**27.7**	**15.0**	**9.9**
British Columbia	**28.7**	11.9	16.8
Alberta			
Conventional (2016)	**35.0**	9.4	25.8
Conventional (2017)	**26.7**	9.4	17.4
Oilsands	**29.3**	22.3	0.3
Saskatchewan	**32.6**	14.3	18.7
Newfoundland & Labrador	**11.8**	4.8	0.0
Nova Scotia	**-3.5**	7.3	-14.2
U.S.	**36.1**	**14.8**	**22.1**
Arkansas	**29.5**	16.5	13.6
Colorado	**31.5**	15.4	16.7
North Dakota	**35.7**	15.0	21.6
Pennsylvania	**25.9**	16.3	10.0
Texas	**36.7**	14.7	22.9
Australia	**-35.5**	15.0	-73.4
Norway	**31.9**	4.2	21.8
United Kingdom	**-2.5**	-3.7	0.5

Source: Authors' calculations.

* Canada average METRRs reflect the new royalty regime in Alberta (2017). With the existing Alberta royalty regime, the Canada-wide METRR equals 30.9 per cent for the "All Levies" case, 15.0 per cent for the "Taxes Only" case, and 13.1 per cent for the "Royalty Levies Only" case.

For Saskatchewan and British Columbia, conventional oil investments are discouraged somewhat more than in Alberta due to other taxes levied on investments (see Table 2). Even though Saskatchewan has the same corporate income tax rate as Alberta, Saskatchewan imposes a capital tax on resource firms, including oil firms, and a five per cent retail sales tax on capital purchases, offsetting some of the advantage of lower royalty payments. British Columbia has a lower corporate income tax than Alberta and Saskatchewan, however it applies a seven per cent provincial retail sales tax on certain capital purchases, which has a substantial impact on the METRR.

Despite its high federal-provincial corporate income tax rate (31 per cent) and net royalty rate (up to 35 per cent, which is deductible from the corporate income tax), Nova Scotia has the most generous royalty system for oil projects in Canada, with significant write-offs provided for expenditures on exploration and development under the royalty base due to high carry-forward interest rates for unused deductions.

Newfoundland & Labrador has a lower corporate income tax rate than Nova Scotia but its new generic royalty regime does not provide the same preferences, especially for development and exploration expenditures. Both Atlantic offshore regimes discourage capital investment less than the western provinces, with lower aggregate METRRs.

As for other jurisdictions, the U.S. is particularly uncompetitive with its federal-state corporate income tax rate ranging from 33 per cent to almost 40 per cent, compared to 26 per cent in British Columbia and 27 per cent in Alberta and Saskatchewan. It also taxes retail sales on capital purchases at slightly higher rates compared to Saskatchewan and British Columbia.

Canada's METRR is higher than Australia's, where the latter's profit-based tax on oil projects provides excessively high deductions and tax credits for exploration and development expenditures.

On the other hand, Norway imposes the highest METRR on offshore oil projects due to its high corporate income and supplementary tax rates that add up to 78 per cent (the supplementary tax is an additional tax that is not deductible from the corporate income tax base). Although capital expenditures are expensed under the Norwegian supplementary tax (unused expenditures are carried forward for a limited period), the combined measures impose a significant disincentive to earn profits in Norway, given its high statutory corporate income tax rate and resource tax rate on income.

This is quite different than U.K. offshore investment. While the U.K. is reducing its corporate income tax to as low as 17 per cent by 2020, it is maintaining it at 30 per cent for ring-fenced oil and gas projects. With its supplementary rate substantially reduced from 32 to 10 per cent (the supplementary tax is not deductible from the corporate income tax base), the combined statutory tax rate was only 50 per cent in 2015 and 40 per cent in 2016, much lower than in Norway. As much of capital is expensed under the supplementary tax, the METRR on marginal projects is negative at -2.5 per cent, meaning that the fiscal system for offshore extraction actually encourages investment.

Overall, oil investments in Alberta are taxed more heavily than they are for the Atlantic offshore, Australia and the U.K., but less than in Arkansas, Colorado, North Dakota, Norway and Texas. Alberta conventional oil is less heavily taxed than similar investments in Saskatchewan and British Columbia due to the absence of a retail sales tax in Alberta and the more competitive royalty regime beginning in 2017.

Most jurisdictions provide incentives for exploration and development for profit-based royalties (oilsands in Alberta and offshore oil in Atlantic Canada, Australia, Norway and the U.K.), resulting in much lower METRRs for exploration and development activities compared to post-production depreciable capital, which tends to distort the capital allocation decision towards relatively more investment in the development phase. However, under the conventional oil royalty in Alberta and other jurisdictions such as British Columbia, Saskatchewan and the United States, the overall fiscal system is more neutral across different assets and therefore is less distortive of investment decisions across assets in the oil sector. On the other hand, the Atlantic offshore and U.K. systems have aggregate METRRs closer to zero, thereby having less impact on aggregate investment decisions.

It is important to remember that these results are derived assuming a WTI price of US$50 per barrel and an exchange rate of 77 U.S. cents per Canadian dollar. However, the price of oil has dipped below US$30 per barrel more than once since the beginning of 2016. On the other hand, the oil price reaching US$70 per barrel in the future is not inconceivable.

When the price of oil rises, there are two possible effects on METRR that work against each other. On one hand, for all jurisdictions that apply royalties to gross revenues, a higher oil price relative to operating costs increases the profit margin. This tends to reduce the marginal effective tax rate on new investment since the effective royalty payment declines as a share of the price-cost margin. We will call this the direct price effect. In our paper, this applies to British Columbia, Alberta and Saskatchewan and all U.S. states.

In addition to this direct effect though, there is a second effect of the price of oil on the METRR that works in the opposite direction, which is relevant to Alberta and Saskatchewan. In these provinces, royalty rates are price dependent, with the government collecting a higher share of revenues when the price of oil rises. This tends to increase the METRR in these provinces as the oil price increases.[29] We will call this the royalty effect on METRR. The royalty rate applied to net revenues from Alberta oilsands also increases with the oil price, with a lower bound of 25 per cent when the WTI is US$55 or less. Overall, it is not immediately clear which of the two effects of the oil price on METRR would dominate in Alberta and Saskatchewan.

Table 3 below reports the METRR under various price scenarios for WTI, ranging from a low of US$30 to a high of US$70.[30] As expected, due to the direct price effect, the METRRs decline as the price of oil rises in British Columbia and the U.S. states, given that royalty rates are independent of price. In Alberta, the royalty effect dominates the direct price effect, and the METRR rises with the price of oil, albeit less so under the new royalty framework. At a price of oil of US$70 dollars, investment in conventional oil in Alberta would be particularly hard hit, with an METRR of more than 38 per cent under the existing framework, the highest of all jurisdictions.[31] In Saskatchewan, the two effects of the price of oil on the METRR almost cancel each other out, and the METRR remains remarkably flat as the price of oil more than doubles from US$30 to US$70 per barrel.

TABLE 3 THE PRICE SENSITIVITY OF METRR ON NEW INVESTMENT (IN PER CENT), 2016

WTI Price (US$/barrel)	30	40	50	60	70
British Columbia	31.3	29.1	**28.0**	27.4	27.0
Alberta					
Conventional (2016)	24.3	29.4	**34.4**	36.5	38.3
Conventional (2017)	19.0	22.5	**26.3**	28.1	29.9
Oilsands	N/A	28.7	**29.3**	30.2	31.2
Saskatchewan	32.7	32.8	**32.8**	32.8	32.9
U.S.	**40.3**	**37.5**	**36.1**	**35.2**	**34.7**
Arkansas	32.1	30.3	**29.5**	28.9	28.6
Colorado	34.7	32.5	**31.5**	30.8	30.4
North Dakota	39.9	37.1	**35.7**	34.9	34.3
Pennsylvania	27.8	26.6	**25.9**	25.5	25.3
Texas	41.2	38.2	**36.7**	35.9	35.3

Source: Authors' calculations.

A decrease in operating costs would work similar to an increase in the oil price, by increasing the profit margin and therefore decreasing METRR. Unlike the price, though, no jurisdiction in Table 3 ties its royalty rates to firm-specific operating costs, and therefore there is no other effect on METRR. Table 4 below illustrates the effect of changes in operating costs on METRR

29 This effect is partially mitigated by the fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Royalty rates in Alberta and Saskatchewan depend on the price of oil expressed in Canadian dollars. As the WTI oil price rises, the Canadian dollar tends to appreciate (see for example Lananh Nguyen and Rachel Evans, "Commodity-Exporter Currencies Advance as Crude Oil Prices Surge," Bloomberg, May 16, 2016, http://www.bloomberg.com/news/articles/2016-05-16/commodity-exporter-currencies-advance-as-crude-oil-prices-surge). Therefore the increase in the price of oil is less pronounced when expressed in Canadian dollars, and with it the increase in royalty rates. Similarly, the decrease in the price of oil of the last year has automatically resulted in lower royalty rates in these two provinces, but the decrease in royalty rates has been less dramatic due to the depreciation of the Canadian dollar.

30 The METRR results for United States in Table 1 are derived assuming an operating cost of US$10 per barrel and a price of US$50, thus a profit margin of 80 per cent. For Canada, we have used the actual profit margins in British Columbia (77 per cent), Alberta (78 per cent) and Saskatchewan (81 per cent) based on historical data on revenues and costs. In Table 3, however, we assume the same operating cost of US$10 per barrel in all jurisdictions and focus on the effect of oil price fluctuations. Hence, the results in Table 3 for a price of oil of US$50 are identical to the aggregate METRR results reported in Table 1 for the U.S. states, but not for the Canadian provinces.

31 We ignore the likely appreciation or depreciation of the Canadian dollar that may accompany an increase or decrease in oil prices, which will dampen shifts in royalty rates and METRR in both Alberta and Saskatchewan, as explained in footnote 22 above.

in the jurisdictions that employ gross royalties, with the price fixed at US$50 per barrel.[32] For all jurisdictions, the METRR increases with the operating cost. The increase is least significant for the oilsands in Alberta, since the gross royalty rate applies only in the pre-payout phase of oilsands projects.

TABLE 4 COST SENSITIVITY OF METRR ON NEW INVESTMENT (IN PER CENT), 2016

Change in Operating Costs	-20%	-10%	0%	+10%	+20%
British Columbia	27.3	27.6	**28.0**	28.4	28.9
Alberta					
Conventional (2016)	33.2	33.8	**34.4**	35.0	35.7
Conventional (2017)	25.5	25.9	**26.3**	26.7	27.2
Oilsands	29.2	29.2	**29.3**	29.3	29.4
Saskatchewan	31.9	32.4	**32.8**	33.3	33.8
U.S.	**35.1**	**35.6**	**36.1**	**36.6**	**37.2**
Arkansas	28.8	29.1	**29.5**	29.8	30.1
Colorado	30.7	31.1	**31.5**	31.9	32.3
North Dakota	34.7	35.2	**35.7**	36.2	36.8
Pennsylvania	25.5	25.7	**25.9**	26.2	26.4
Texas	35.7	36.2	**36.7**	37.3	37.9

Source: Authors' calculations.

CONCLUSIONS

At existing oil prices, we show that Alberta's new fiscal regime for conventional oil is more competitive in attracting investment compared to the 2016 regime. While it is not badly out of line or better than most jurisdictions in this study, it is still less competitive than regimes in Australia, the U.K. and Pennsylvania, as well as Nova Scotia and Newfoundland & Labrador. At higher oil prices (US$70 WTI), the price-sensitive conventional royalty, unlike that of the U.S., will result in higher effective tax rates on new investments compared to British Columbia, Arkansas and Pennsylvania, but below that of Saskatchewan, Colorado, North Dakota and Texas.

We also find that Saskatchewan and British Columbian oil investments are disadvantaged, not so much due to their royalty structure, but as a result of their retail sales taxes, which result in the taxation of capital purchases and, in the case of Saskatchewan, a capital tax paid by resource companies.

We further note that the new generic royalty developed by Newfoundland & Labrador is simpler and less distortionary compared to its previous royalty regime.

[32] As in Table 3, and as explained in footnote 29 above, for this exercise we use the same benchmark operating cost for conventional oil of US$10 per barrel in all jurisdictions. As a result, the figures reported for British Columbia, Alberta and Saskatchewan are slightly different than those reported in Table 1, where we use historic data for the profit margins in these three jurisdictions. For oilsands, we use a benchmark operating cost of US$21.40 per barrel for steam-assisted gravity drainage and US$20.50 per barrel for mining operations.

APPENDIX

PARAMETERS USED IN THE METRR CALCULATIONS

TABLE A1 TAX PARAMETERS BY JURISDICTION, 2016

Canada	British Columbia	Alberta	Saskatchewan	Newfoundland and Labrador	Nova Scotia
Corporate income tax	26%	27%	27%	30%	31%
Federal CIT	15%	15%	15%	15%	15%
Provincial CIT	11%	12%	12%	15%	16%
Effective sales tax rate on depreciable capital	1.8%	N/A	0.9%	N/A	N/A
Revenue-based royalty	0-30%* (varying with output)	0-40% (varying with oil price and output)	varying with oil price and output**	N/A	N/A
Rent-based (net) royalty	N/A	25%-40% (varying with oil price)	N/A	50%***	2-tier 20%/35%
No uplift / return allowance for income taxes					
Uplift for exploration	N/A	LTBR	N/A	N/A	2-tier 20%+LTBR/ 45%+LTBR
Uplift for development	N/A	LTBR	N/A	N/A	2-tier 20%+LTBR/ 45%+LTBR
Uplift for depreciable capital	N/A	LTBR	N/A	N/A	2-tier 20%+LTBR/ 45%+LTBR

* New oil.

** Fourth-tier non-heavy oil.

*** R-factor above three.

U.S.	Arkansas	Colorado	North Dakota	Pennsylvania	Texas
Combined corporate income tax $U=U_f(1-U_s)+U_s$	37.26%	36.01%	35.79%	39.60%	33.40%
Federal CIT (U_f)	32.90%	32.90%	32.90%	32.90%	32.90%
State CIT (U_s)	6.50%	4.63%	4.31%	9.99%	0.75%
Effective sales tax rate on depreciable capital	2.6%	2.1%	1.8%	1.8%	2.3%
Revenue-based royalty*	12.50%	16.67%	18.75%	12.50%	25.01%**
Rent-based (net) royalty	N/A	N/A	N/A	N/A	N/A
Severance tax	5.00%	5.00%	10.00%	0.00%	4.60%
Effective royalty rate***	21.09%	26.04%	33.59%	15.63%	35.58%
No uplift/return allowance of any kind					

* Royalty due on state-owned land.

** Includes the franchise tax.

*** Combined royalty and severance tax, taking into account the partial offsetting mechanism between the two.

Other Countries	Australia	Norway	U.K.
Combined corporate income tax	30%	78%	40%
Corporate income tax	30%	27%	30%
Supplementary / special tax on oil (Sharing the CIT base)	N/A	51%	10%
Revenue-based royalty	N/A	N/A	N/A
Rent-based (net) royalty	40%	N/A	N/A
Uplift under corporate income tax			
Exploration	N/A	N/A*	10%
Development	N/A	N/A	10%
Depreciable capital	N/A	N/A	N/A
Uplift under supplementary tax			
Exploration	N/A	N/A*	10%
Development	N/A	5.5%, 4 years	10%
Depreciable capital	N/A	5.5%, 4 years	N/A
Uplift under rent tax			
Exploration	LTBR + 15%	N/A	N/A
Development	LTBR + 5%	N/A	N/A
Depreciable capital	LTBR + 5%	N/A	N/A

* Exploration costs in Norway are expensed and the tax value of exploration expenses refunded for each year of tax loss.

TABLE A2 NON-TAX PARAMETERS BY JURISDICTION, 2016

Canada	Australia	Canada	Norway	U.K.	U.S.
Inflation rate*	1.81%	1.92%	3.88%	1.20%	1.97%
Real interest rate	3%	3%	3%	3%	3%
Nominal interest rate	4.81%	4.92%	6.88%	4.20%	4.97%
Long-term bond rate**	2.5%	1%	N/A	N/A	N/A

* Ten-year average GDP deflator inflation rates based on OECD data (2004–2014).

** Trading Economics, 10-year government bond rate Feb. 2016.

TABLE A3 COMMON PARAMETERS FOR ALL JURISDICTIONS, 2016

Debt-to-asset ratio	40%
Average time to build — exploration	5 years
Average time to build — development*	3 years
Time from making investment to payout — exploration	10 years
Time from making investment to payout — development	8 years

* Except for Newfoundland & Labrador, where we assume it takes 10 years for a project to reach an R-factor of three or more.

TABLE A4 CAPITAL WEIGHTS BY PROJECT TYPE, 2016

	Conventional	Oilsands	Offshore
Exploration	26.7%	2.4%	28.0%
Development	37.6%	15.2%	50.6%
Depreciable assets	33.3%	79.9%	21.4%
Inventory	2.4%	2.5%	0.0%
Aggregate	**100.0%**	**100.0%**	**100.0%**

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