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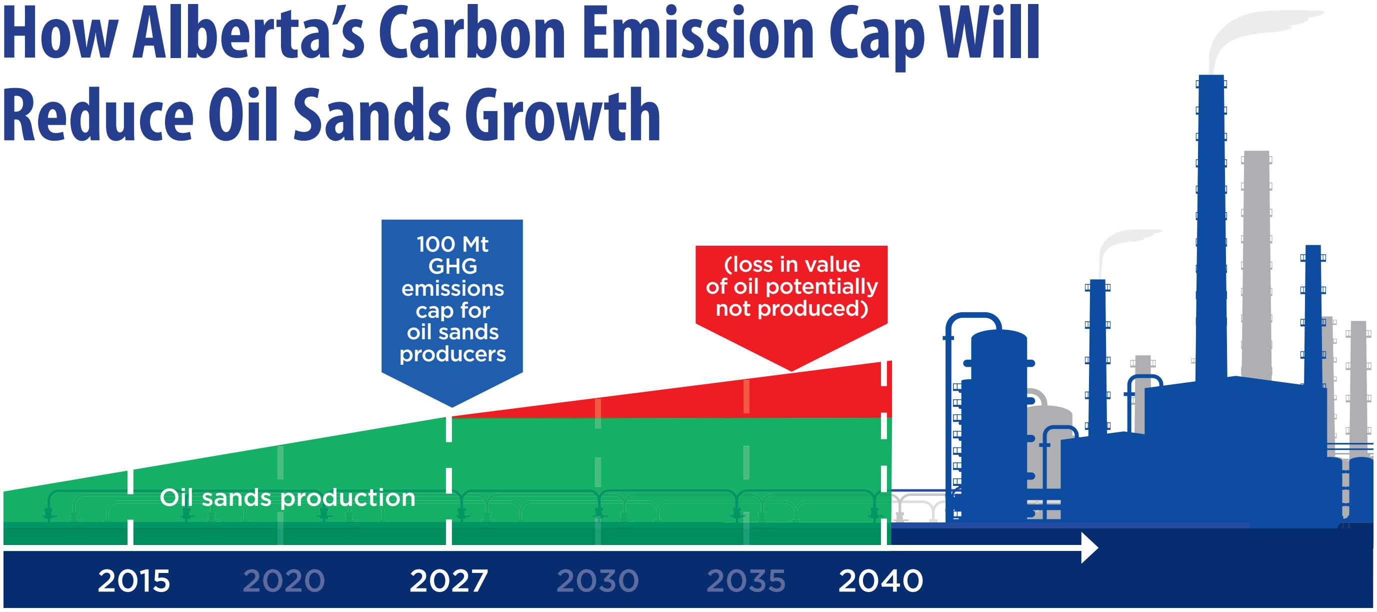
How Alberta's Carbon Emission Cap Will Reduce Oil Sands Growth



by Kenneth P. Green and Taylor Jackson

Summary

- The Alberta government has proposed implementing a 100 megatonne (Mt) cap on greenhouse gas (GHG) emissions that result from oil sands operations.

- This paper estimated future emissions levels from oil sands production using oil sands production forecasts to 2040 from the National Energy Board.

- Based on estimates of future production, this policy has the potential to constrain future oil sands production. In a scenario based on current emissions intensity levels, the policy could reduce cumulative production between 2025 and 2040 by 3.34 billion barrels of oil. In a scenario where the emissions intensity of oil sands production is reduced, the policy could result in cumulative production losses between 2027 and 2040 totaling 2.03 billion barrels of oil.

- The cumulative value of the lost production could be large, totaling CA$254.74 billion (in 2015 dollars) in a scenario based on current emissions intensity levels. In a scenario where the emissions intensity of oil sands production is reduced, the cumulative lost value could be CA$153.41 billion (in 2015 dollars).

- The policy could cumulatively abate 236 Mt of CO_2 equivalents, at an average cost of CA$1,035 (in 2015 dollars) per tonne of GHG emissions in the current emissions intensity level scenario between 2025 and 2040. The cumulative level of GHG abatement would be lower in a scenario where emissions intensity reductions occur but come at a higher cost.

- The 100 Mt cap on GHG emissions appears to place large costs on Canadians by potentially constraining future growth in oil sands development, while providing little in the way of avoided GHG emissions.

Introduction

Alberta's oil sands represent the world's third largest reserve of oil,[1] and their development has produced considerable prosperity and wealth for the people of Alberta and Canadians across the country. Even amidst lower oil prices, a number of different analyses have projected that production from the oil sands will continue to grow well into the future (see, for example, NEB, 2016; IEA, 2016). To put this into perspective, one recent estimate forecasted that oil sands production could more than double by 2040 (NEB, 2016).

However, future growth in oil sands production may be hampered by recent policy changes, which include, but are not limited, to new environmental regulations. We have already noted that recent policy uncertainty in the province has led to a decline in investor confidence (Green and Jackson, 2015; McKitrick and Green, 2016; IEA, 2016). In fact, in its recent *Medium Term Oil Report*, the IEA concluded that "[h]eightened environmental concerns, a lack of pipeline access to new markets and the unknown impact of the victory by the New Democratic Party in Alberta's elections last year are causing companies to slow development" (IEA, 2016: 51).

Despite concerns about future investment, policy is changing, particularly in the area of environmental regulations. On November 22, 2015, Alberta's Premier Rachel Notley unveiled the province's climate change strategy, which included sharply higher (and more broadly applied) carbon taxes; a greenhouse gas (GHG) emissions cap on oil sands operations; a phase-out of coal-generated electricity; a plan for the replacement of coal-generated capacity with renewable energy sources; and a strategy to reduce methane emissions from the oil and gas sector (CBC, 2015, Nov. 22). The one policy that stands out as having the most potential to slow the growth of production and investment in Alberta's oil sands is the Alberta government's proposed 100 megatonne (Mt) per year cap on greenhouse gas emissions (GHG) from the oil sands.

This paper delves into what this cap may mean for the future of oil sands development. We present estimates for future oil sands production to get an indication of their potential growth. Estimates of emissions intensity are used to determine at what point oil sands production will have to be left undeveloped due to the emissions limits and we provide estimates of the potential lost value of the unextracted oil. The paper concludes by looking at Alberta's oil sands emissions in a global context to get a sense of the environmental and GHG benefits that the Alberta policy will potentially yield.

Oil sands production potential

Demand for oil is going to continue to rise well into the future, presenting Canada with large opportunities to develop and export its energy resources. The International Energy Agency's *World Energy Outlook 2015* contains a number of oil demand projections under different policy scenarios, providing an outlook for what will be needed of future supplies if demand is to be met (IEA, 2015).[2]

[1] According to the US Energy Information Administration (EIA), Canada's proved oil reserves in 2015 were estimated to total 172 billion barrels of oil, third only to Venezuela and Saudi Arabia (EIA, 2016). About 97% of Canada's oil reserves come from Alberta's oil sands, which are estimated to total 166.3 billion barrels of oil (NR Canada, 2016). The fourth largest reserves in the world are held by Iran and total 157.8 billion barrels of oil (EIA, 2016).

[2] Under the IEA's Current Policies Scenario, oil prices are forecasted to reach $83 per barrel in real

Table 1: Oil Demand by Scenario (million barrels per day)

		OECD	Non-OECD	Bunkers*	World Total
Current Policies	2014	40.7	42.9	7.0	90.6
	2020	40.1	49.7	7.8	97.5
	2040	34.4	71.4	11.2	117.1
	Growth 2014-2040	-15%	66%	60%	29%
New Policies	2020	39.4	48.9	7.6	95.9
	2040	29.8	63.6	10.0	103.5
	Growth 2014-2040	-27%	48%	43%	14%
450 Scenario	2020	38.8	47.7	7.3	93.7
	2040	20.5	46.7	6.9	74.1
	Growth 2014-2040	-50%	9%	-1%	-18%
Low Oil Price	2020	39.9	49.4	7.7	97.0
	2040	31.3	65.4	10.4	107.2
	Growth 2014-2040	-23%	52%	49%	18%

*Includes international marine and aviation fuels.

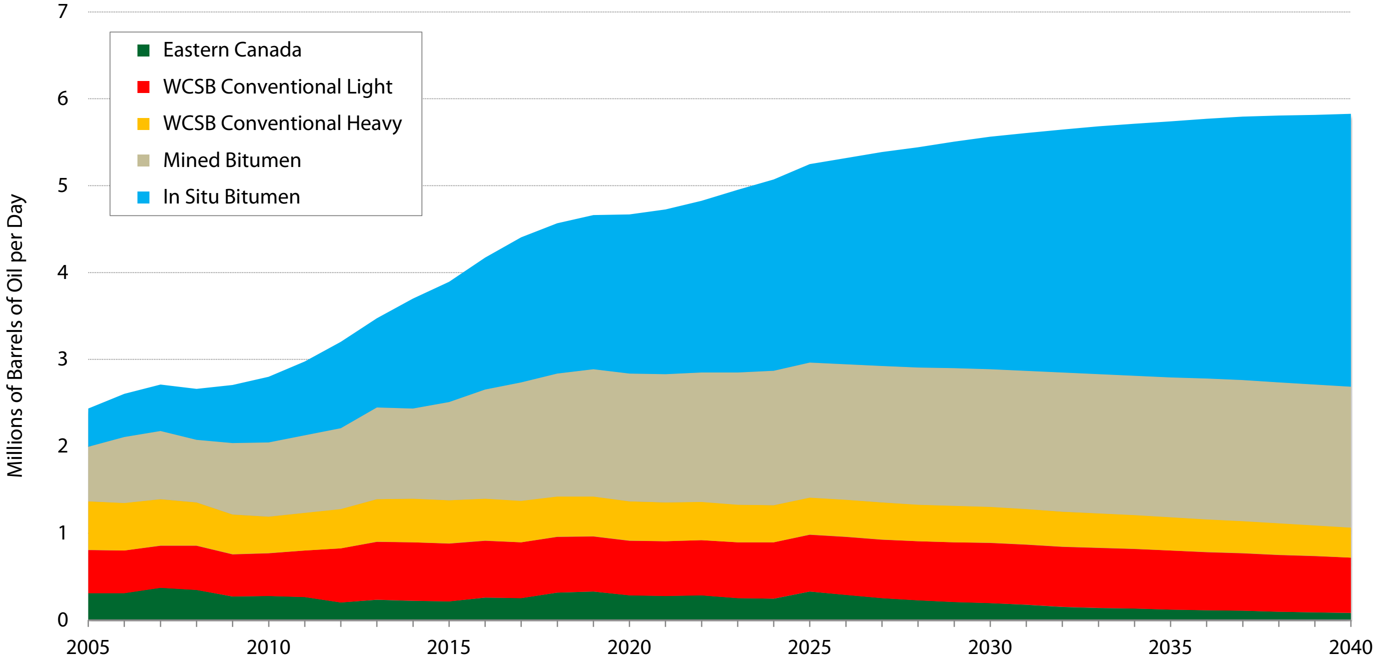
Source: IEA, 2015.

Table 1 displays demand projections under four scenarios.[3] In three of the four scenarios, global oil demand is expected grow from 2014 to 2040.

2014 dollars by 2020, increasing to $150 per barrel in real 2014 dollars by 2040. This is the IEA scenario with the highest forecasted growth in oil prices. In the scenario with the lowest forecasted growth, the Low Oil Price Scenario, prices only reach $85 per barrel in real 2014 dollars by 2040 (IEA, 2015).

[3] Three of the scenarios are dependent on policy choices. The *Current Policies Scenario* only considers policies that had been formally adopted as of mid-2015 and assumes that these remain unchanged. The *New Policies Scenario* takes into consideration the current policies governments had implemented as of mid-2015 as well as relevant intentions that had been announced, which included components of the Intended Nationally Determined Contributions (INDCs) that countries had submitted by October 1, 2015, for the United Nations Framework Convention on Climate Change (UNFCCC) Conference of Parties 21 (COP 21). That scenario takes a cautious approach when implementing policies in the projection in order to better capture the possible effects of the institutional, political, and economic realities that could stand in the way of implementing policies such as support for renewable energy, carbon pricing, energy subsidy reform, the phase out or implementation of nuclear power, etc. The 450 Scenario assumes a set of policies that would limit emissions from the energy sector enough to limit atmospheric concentrations of GHG by 2100 to around 450 parts per million, the concentration asserted by some to be necessary to limit warming to 2°C above pre-industrial levels. The *Low Oil Price Scenario* is one where the current oversupply in the global market takes a longer time to reduce; it assumes lower rates of economic growth

Figure 1: Total Crude Oil Production, Reference Case, 2005–2040



Source: NEB, 2016.

Demand growth is the largest under the current policy scenario, with global demand increasing by 29%, and non-OECD country demand increasing by 66% in the 26-year period. In all scenarios almost all the growth in oil demand occurs in the non-OECD countries. In all scenarios OECD oil demand is expected to fall between 2014 and 2040.[4]

Strong demand growth implies that there will be opportunities for Canadian production to grow. The National Energy Board's (NEB) recent Canada's Energy Future 2016 report, which projects energy supply and demand to 2040, is an indication of Canada's energy development potential. The report has four core assumptions that underpin the board's core cases: a baseline reference case, a high oil price case, and a low oil price case.[5] The four assumptions are:

1. All energy production will find markets and infrastructure will be built as needed.

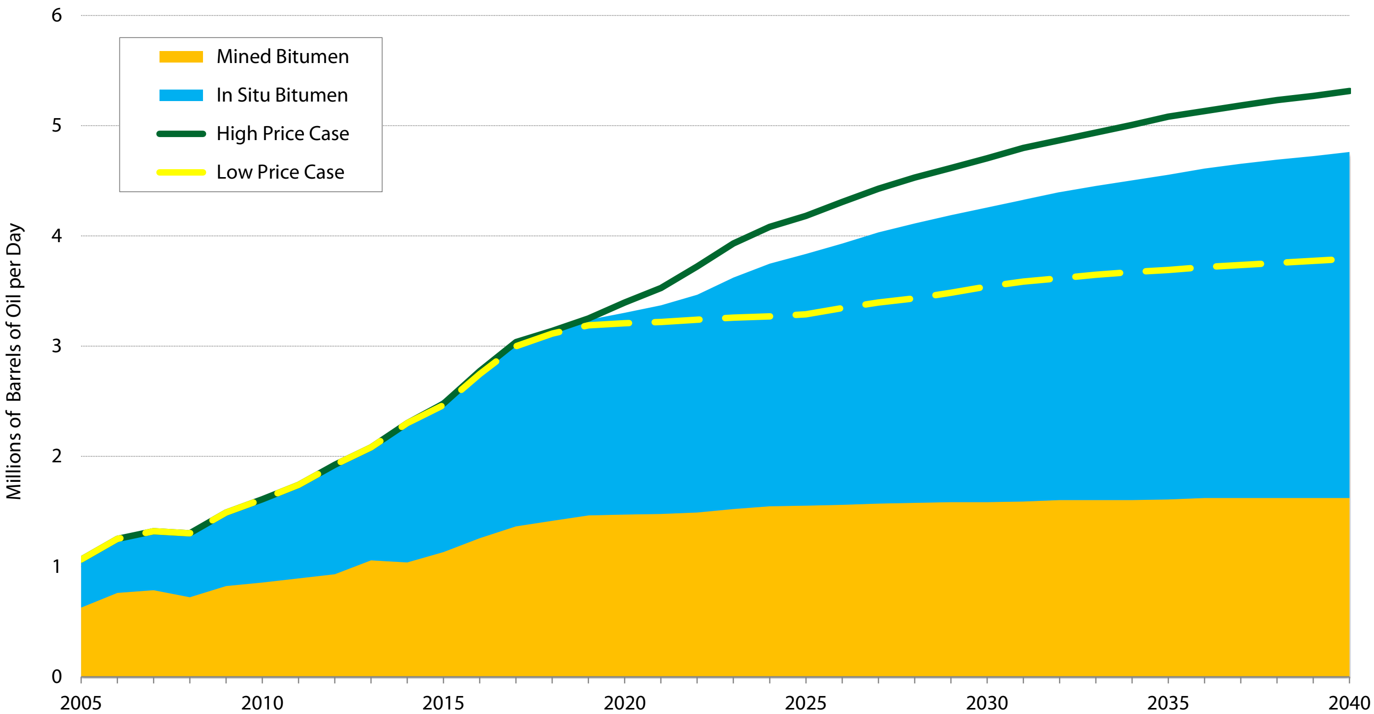
2. Only policies and programs that are law at the time of writing are included in the projections. As a result, any policies under consideration, or new policies developed after the projections were completed in the summer of 2015, are not included in this analysis.

and that the market price in the future is much lower than in other scenarios.

[4] The IEA posits that demand for oil in OECD countries will weaken due to a continuation of structural trends. This downward shift in demand is expected to be led by Europe and Japan, which have the highest taxes on oil products (IEA, 2015).

[5] The high and low oil price scenarios used by the NEB differ from the reference case for the most part because of different assumptions about future economic conditions (NEB, 2016).

Figure 2: Oil Sands Production Projections, 2005-2040



Source: NEB, 2016.

3. Environmental and socio-economic considerations beyond the included policies and programs are outside the scope of this analysis.

4. Energy markets are constantly evolving. The analysis presented in *Canada's Energy Future 2016* is based on the best available information at the time of finalizing the analysis and results, which was the summer of 2015. (NEBa, 2016: 11)

The NEB's three scenarios provide baseline projections of assumed production potential before implementation of the 100 Mt oil sands emissions cap policy evaluated in this paper.

Figure 1 shows the NEB's reference case projection of Canadian oil production to 2040. Overall oil production is expected to grow from 2.43 million barrels per day (b/d) to 5.82 million b/d in 2040, a 57% increase. From 2014 (the last year of historical data) to 2040, oil production from Eastern Canada and production of light and heavy conventional oil from the Western Canadian Sedimentary Basin (WCSB) is expected to decline. All growth in Canadian oil production in this period is expected to come from oil sands bitumen development.

Figure 2 looks only at growth in production from the oil sands. For the reference case, oil sands production from 2014 to 2040 is projected to grow from 2.30 million b/d to 4.76 million b/d, a growth of 107%. In the high oil price scenario, oil sands production is projected to reach 5.31 million b/d in 2040, a 131% increase from 2014. In the low price scenario, production is expected to reach 3.79 million b/d, or to increase 65% from 2014 levels.

Table 2: Emissions from the Oilsands, 1990-2013

	1990	2000	2005	2009	2010	2011	2012	2013
Mt CO2-eq								
Global GHG emissions	29,079	32,715	37,417	39,832	41,477	42,684	43,286	n/a
National GHG total	613	745	749	699	707	709	715	726
Oil sands (mining, in-situ, upgrading)	15	24	32	46	51	54	58	62
Mining and extraction	4	6	10	13	15	15	16	16
In-situ	4	7	10	17	20	21	25	27
Upgrading	6	11	13	16	17	17	18	18
Percentage of global emissions from oil sands	0.05%	0.07%	0.09%	0.12%	0.12%	0.13%	0.13%	n/a
Percentage of Canadian emissions from oil sands	2.45%	3.22%	4.27%	6.58%	7.21%	7.62%	8.11%	8.54%

Notes:
Emissions exclude land-use, land-use change, and forestry.
Upgrading is the process transforms the thick and heavy bitumen into a lighter crude oil known as synthetic crude oil or upgraded crude oil.

Source: Environment Canada, 2015; World Resources Institute, 2015.

One important trend to note is the difference in oil sands production growth between open pit mining operations and in-situ.[6] In 2005, 59% of oil sands production was through mining. Mining became the minority in 2014 when it was only 45% of production; and its share of production is expected to continue declining throughout the period, reaching 34% in 2040. From 2014 to 2040, oil sands production from mining is projected to grow from 1.04 million b/d to 1.62 million b/d, while in-situ production is expected to more than double from 1.26 million b/d in 2014 to 3.14 million b/d in 2040.

[6] In-situ (meaning "in place") oil sands production refers to production that occurs through the use of heat or solvents to decrease the viscosity of the bitumen so that it can be pumped up to the surface.

The main reason for the growth in in-situ production is that the economics are more favourable over the projection period due to the lower initial capital expenditures of in-situ projects (NEB, 2016).

To be clear, these are projections and a number of uncertainties and assumptions lie beneath them. A concrete example of this is the difference between the NEB's *Energy Future* 2016 outlook, which this report uses, and the NEB's previous outlook (NEB, 2013). In the 2013 projection, oil sands production was expected to reach approximately five million b/d by 2035. In the latest projection, which reflects the current low price environment, production in the reference case is expected to remain under five million b/d, even though the projection horizon is five years further in the future (NEB, 2016, 2013).

Table 3: Historical Emissions Intensities, 2005 and 2009 to 2013

	2005	2006	2007	2008	2009	2010	2011	2012	2013	Average 2005-2013	Average 2011-2013
Mt CO_2-eq per million barrels of oil											
Mined bitumen	0.044	n/a	n/a	n/a	0.043	0.048	0.046	0.047	0.041	0.045	0.045
In-situ bitumen	0.062	n/a	n/a	n/a	0.070	0.073	0.068	0.069	0.072	0.069	0.070
Kg CO_2-eq per barrel of oil											
Mined bitumen	43.56	n/a	n/a	n/a	43.23	48.04	46.01	46.96	41.48	44.88	44.82
In-situ bitumen	62.23	n/a	n/a	n/a	69.86	72.60	67.76	68.73	72.15	68.89	69.55

Source: Environment Canada, 2015; NEB, 2016.

These projections give us a possible sense of what the oil sands development potential is given the best available information at this time; and they allow us to assess how the 100 Mt emissions cap on the oil sands might affect future production levels.

Oil sands and greenhouse gases

To understand the impacts of the annual 100 Mt GHG emissions cap placed on oil sands operations, we must first analyze the absolute amount of emissions currently coming from the oil sands and their intensities (i.e., emissions per million barrels of production).

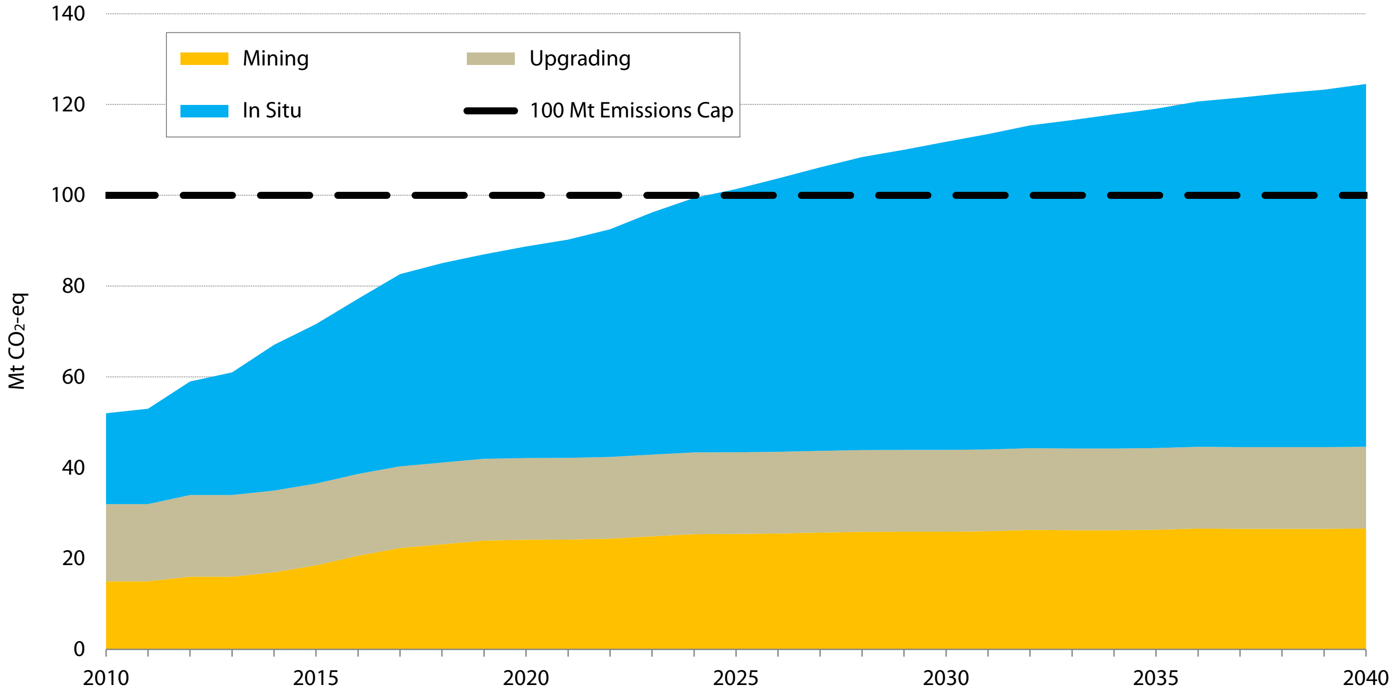
Table 2 gives annual GHG emissions from the oil sands from 1990 to 2013. As the table shows, absolute emissions from the oil sands have grown substantially, in line with increased production levels. The largest increase in emissions has come from in-situ production, which has become the dominant form of oil sands extraction. In-situ production, while having smaller land use impacts and no tailings ponds, produces larger volumes of GHGs per barrel of oil produced than bitumen recovery via mining operations.

Although GHG emissions from oil sands operations have become a larger share of Canada's total GHG emissions over the period, they continue to be a very small share of global emissions.

Table 3 presents GHG emission intensities for mined and in-situ oil sands extraction, using the available historical data for the years 2005 and 2009-2013. For the most part, it appears that emission intensities for both kinds of oil sands bitumen production has leveled off in recent years, which was noted by Environment Canada (2015) in its United Nations Framework Convention on Climate Change (UNFCCC) submission.

The estimated emissions intensities from oil sands production can be used to project when production may have to be curtailed in order to comply with the 100 Mt emissions regulation. This scenario will use the 2011-2013 aver-

Figure 3: Emissions from Oil Sands Production, Current Emissions Intensity Levels, 2010-2040



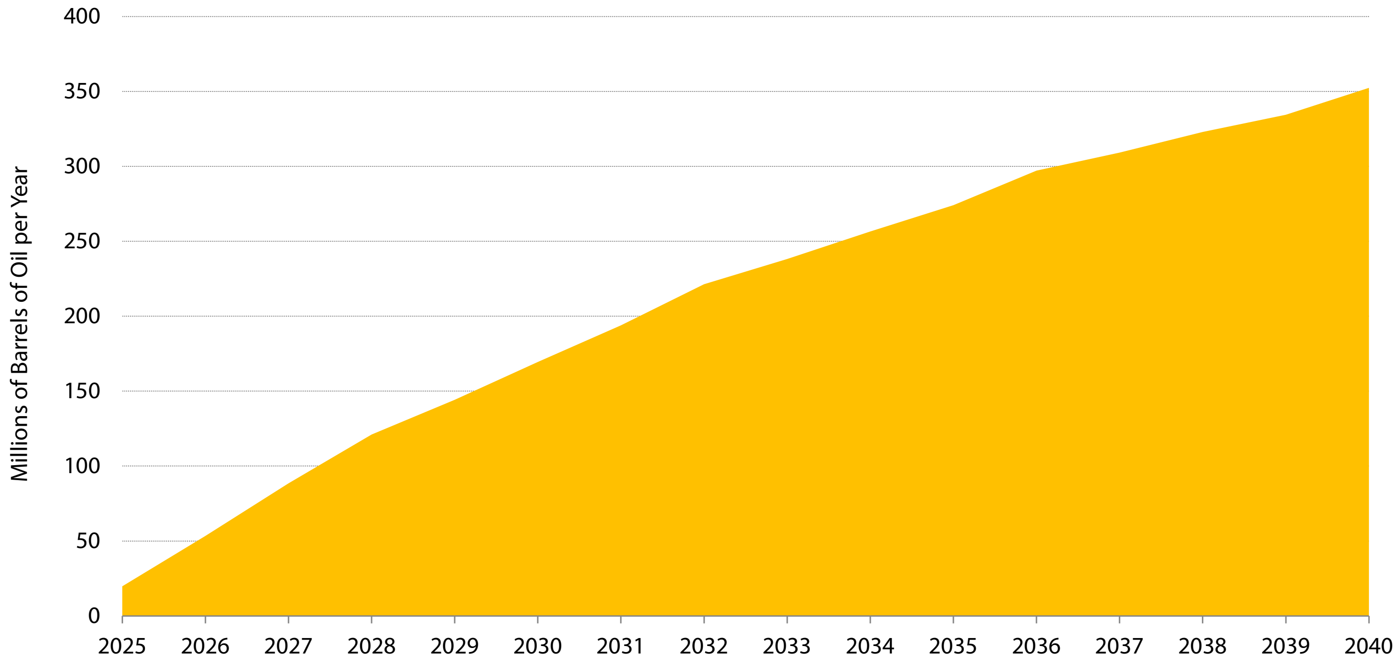
Source: Environment Canada, 2015; NEB, 2016; author calculations.

age emissions intensity value to determine in what year the 100 Mt cap will begin limiting production, assuming that emissions intensity levels are held at the 2011-2013 average. GHG emissions from upgrading will be held at their 2013 level of 18 Mt of carbon dioxide equivalents (CO_2-eq) for a number of reasons. They include:

- expectations that upgrading capacity is expected to grow little throughout the period, as evidenced by the projected start-up of two oil sands mining projects that are not tied to upgraders (Kearl and Fort Hills);
- the Northwest Upgrader currently under construction will allow for the capture of CO_2 to be used in enhanced oil recovery at conventional wells; and
- the Alberta government has stated that the 100Mt cap will contain "provisions for cogeneration and new upgrading capacity," although it is not completely clear what this will entail at this time (NEB, 2016; Alberta, n.d.; Angevine, 2016).

Figure 3 shows projected oil sands emissions given the assumptions detailed above and the NEB's production projections. Under these assumptions, emissions would grow from 52 Mt CO_2-eq in 2010 to approximately 125 Mt CO_2-eq in 2040. However, in 2025 emissions would be greater than 100 Mt and production would have to be curtailed. As a baseline estimate at current intensity levels, this figure shows that in-situ production emissions intensities will need to be lowered significantly if production is not to be significantly constrained.

Figure 4: Lost Production, Current Emissions Intensity Levels, 2025-2040 (Millions of Barrels of Oil per Year)



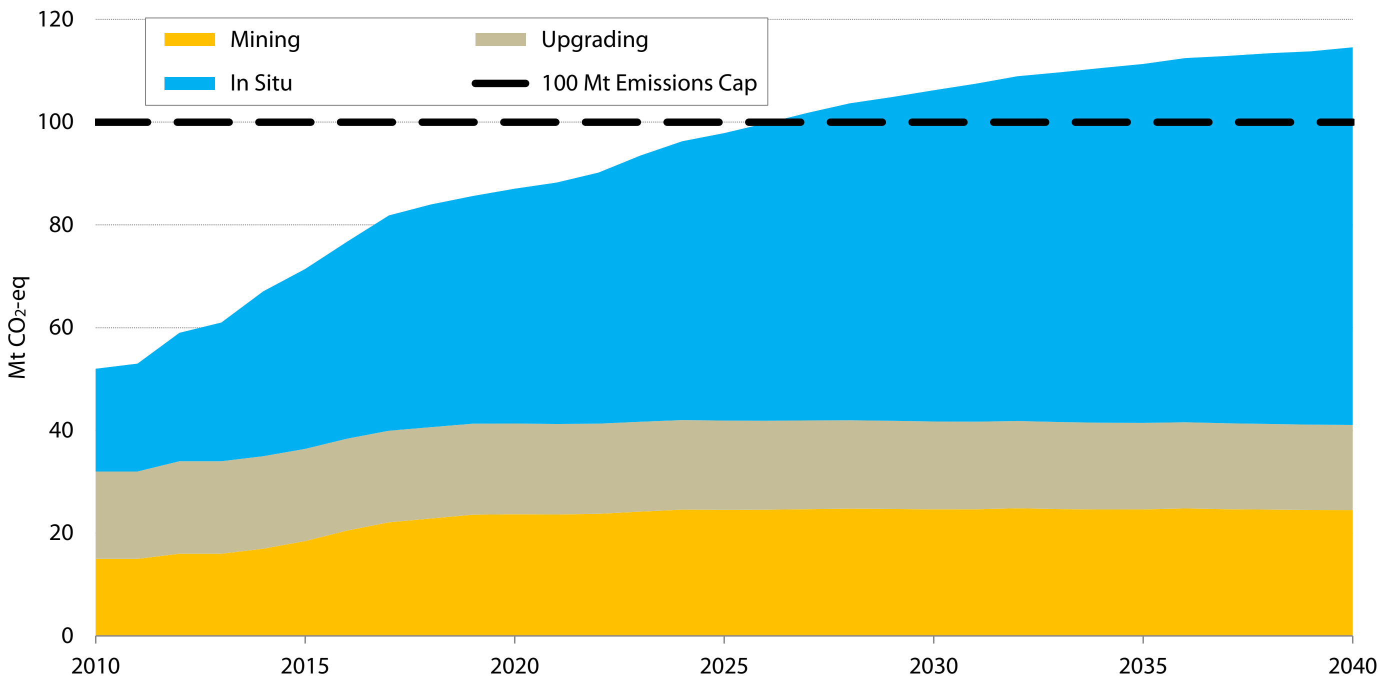
Source: Environment Canada, 2015; NEB, 2016; author calculations.

Figure 4 shows the extent to which oil sands bitumen production could be constrained as a result of the emission cap starting in 2025 if GHG emissions intensities are not reduced. This calculation assumes that all of the constrained production is expected to come from in-situ extraction since mining is expected to expand little, particularly after 2025, and mining is the less emissions-intensive form of production. Based on the NEB's production projections, initial production losses under current emissions intensity levels will be modest, at 20 million total barrels, or 0.05 million b/d of production in 2025. By 2040, however, production losses could reach 352 million barrels, or 0.96 million b/d. Cumulative lost production due to the 100 Mt emissions cap, given current emissions intensity levels and the NEB's projections, could reach 3.397 billion barrels of oil. This is equal to 13% of projected production from 2025 to 2040, or slightly under the total oil sands production that took place from 2005 to 2011.

Emissions intensity reductions

While the scenario above projects emissions and production losses using current emissions intensity levels—an approach that somewhat reflects the stagnation in emissions intensity reductions over the last decade, it is quite likely that, given the term of the NEB's projection, emissions intensities from oil sands extraction will be reduced to a certain extent in response to the 100 Mt emission regulation. Indeed, organizations such as Carbon Management Canada and the Canadian Oil Sands Innovation Alliance are but two of the groups

Figure 5: Emissions from Oil Sands Production, Emissions Intensity Reductions, 2010–2040



Source: Environment Canada, 2015; NEB, 2016; Murillo, 2015; author calculations.

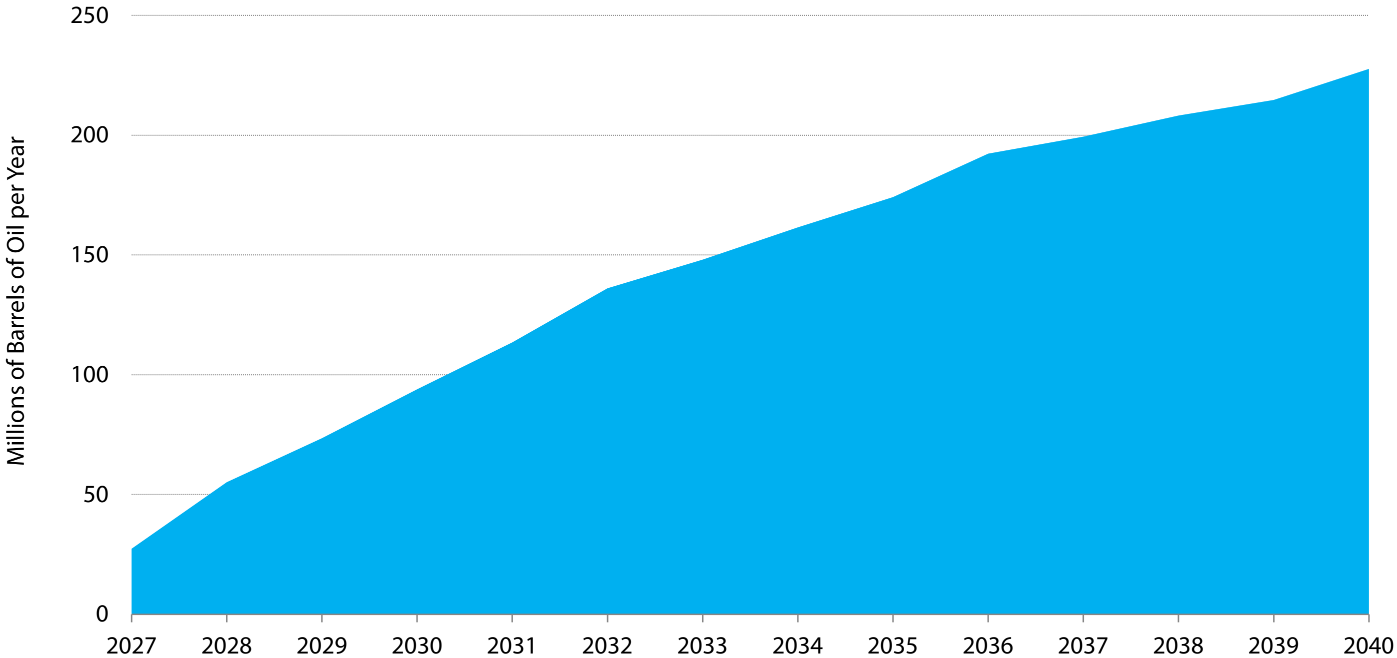
working towards improving the environmental performance of oil sands extraction.[7] This section aims to provide a sense of how a reduction in emissions intensities might affect production levels under the 100 Mt cap.

How much can one reasonably expect emissions intensities to be reduced? Murillo (2015) recently produced a number of forecasts for oil sands industry energy requirements and GHG emissions for the period from 2015 to 2050. These forecasts provide the basis for an emissions scenario that we applied in order to gain an understanding of how efforts to reduce GHG emissions intensities might help mitigate the effects of the emissions cap policy.

To derive his emissions intensities projections, Murillo (2015) estimated energy requirements for different oil sands projects and GHG emissions and intensities in oil sands operations. Here we focus on his business-as-usual scenario, which "represents conditions that are most likely to unfold based on historic trends" (p. xii). Murillo (2015) projected that between 2014 and 2050, GHG intensity from overall oil sands output (mining, in-situ, and upgrading), given all of the assumptions made, could decline by 11.50%, or a compound annual decline rate (CADR) of 0.32%. For our purposes, the CADR of 0.32%

[7] In his 2015 analysis of future GHG emissions, Murillo also provided estimates for a scenario where emissions intensities improved by a greater amount than the baseline. These improvements came from increasing the efficiency with which energy is used. Improvements in energy efficiency are one possible way for oil sands producers to reduce their emissions intensities. However, if reservoir quality declines, the energy intensity of production may increase and lead to high emissions intensities.

Figure 6: Lost Production, Emissions Intensity Reductions, 2027-2040 (Million Barrels of Oil per Year)



Source: Environment Canada, 2015; NEB, 2016; Murillo, 2015; author calculations.

was applied to all three types of oil sands activity starting in 2015. This provided an indication of how modest reductions in emissions intensities could affect oil sands production under the 100 Mt emissions cap.

Figure 5 shows emissions from oil sands production given the NEB’s production projections and annual emissions intensity reductions of 0.32%. Under these assumptions, emissions from oil sands production will move beyond 100 Mt CO_2-eq in 2027, two years later than under current emissions intensity levels. In this scenario, emissions will reach approximately 115 Mt in 2040, 10 Mt below the levels expected in 2040 if there are no reductions in emission intensities.

Figure 6 shows how, starting in 2027, oil sands production is expected to be constrained due to the GHG emissions cap. This estimate again assumes that all of the constrained production is from in-situ extraction. In this case, 2027 production is curtailed by 27.40 million barrels of oil, or 0.08 million b/d. In 2040, the constraint on production could be as high as 227.70 million barrels, or 0.62 million b/d. Total constrained production between 2027 and 2040, under the scenario where emissions intensity levels are reduced to the indicated extent, could be 2.03 billion barrels of oil.

The scenario where modest reductions in emissions intensity occur allows more oil sands production to take place. As already noted, with no reductions in GHG emissions intensities cumulative production losses could reach 3.40 billion barrels of oil sands production as a consequence of the annual GHG emissions ceiling. But with emissions intensities reduced to the extent assumed, cumulative production losses could total 2.03 billion barrels of oil. This means that modest emissions intensity reductions could allow an additional 1.37 billion barrels of oil to be produced between 2025 and 2040. Of course, reductions in emissions intensity would have to be much larger than we have assumed if oil sands production is to reach the levels forecast by the NEB. This is particularly true for in-situ production, which is expected to be the source of most of the additional oil sands production.

It should also be noted that the above estimates of emissions intensity reductions are modest and represent a conservative estimate of what could happen to production given some reductions in emissions intensity. However, projections of future oil sands emissions intensity are highly uncertain and will depend on a number of different variables including the source of energy used in extraction, potential technological breakthroughs, the quality of the reservoirs, and a number of other factors. Due to the uncertainty, we include only the modest intensity reduction estimate, which provides a sense of just how large intensity reductions will need to be in order for oil sands production to be in line with the NEB's projections.

Value of constrained oil sands production

Essentially, the gross value of the constrained production is the product of the volume of constrained production and the per-barrel price that is realized. For the purpose of this paper, we assume that if the production were not constrained, the producers would realize the price of Western Canada Select (WCS) crude oil blend.[8] WCS is a heavy crude oil blend composed mostly of bitumen but also including sweet synthetic crude oil (from upgraders) and conventional heavy crude oil as well as diluents (i.e., condensates). The diluent is required to reduce the density and viscosity of the heavy blend so that it can be transported via pipeline more efficiently. WCS is mixed and priced at Hardisty, Alberta.[9]

To forecast the potential lost value from the emissions cap we used the WCS price forecast in the NEB's *Energy Futures* report.[10] Deloitte's forecast of Pentanes Plus and condensate[11] was the source of the estimate of the per-barrel cost of diluent. That cost was subtracted from the WCS price before the value of the lost (i.e., constrained) oil production was estimated (Deloitte, 2016).

Table 4 provides estimates of both the total projected value of the in-situ oil given the NEB's production projections as well as the potential lost value of the oil that would not be produced as a result of the 100 Mt cap on oil

[8] In fact, some producers choose not to sell their production at Hardisty but instead at refinery market destination points where they are able to realize higher prices but are responsible for the transportation cost from Hardisty.

[9] This blend of oil trades at a discount to the lighter, sweeter, Brent and West Texas Intermediate (WTI) benchmark crudes due to the lower quality (which makes it harder to refine) and transportation costs from Hardisty.

[10] In their analysis, the NEB forecasts Brent prices and then assumes that WTI trades at a constant $5 per barrel discount to Brent and that WCS trades at a $17 per barrel discount to WTI. However, these price differentials are quite large when compared to broader historical differentials. This may make our results more conservative.

[11] Pentanes Plus and condensate are natural gas products with similar properties, often used as diluents for bitumen and heavy crude oil, enabling them to be transported.

Table 4: Value of In-Situ Oil and Potential Losses (in 2015 CA$ millions)

	Total Projected Value of In-Situ Oil	Value of Lost Production – No Efficency Reductions	Value of Lost Production – Emissions Intensity Reductions
2025	$50,016	$1,185	—
2026	$53,619	$3,306	—
2027	$57,346	$5,652	$1,750
2028	$61,096	$7,972	$3,634
2029	$64,512	$9,790	$4,992
2030	$68,210	$11,848	$6,568
2031	$70,899	$13,767	$8,061
2032	$73,713	$15,965	$9,817
2033	$76,171	$17,447	$10,846
2034	$78,720	$19,084	$12,016
2035	$81,165	$20,708	$13,159
2036	$83,905	$22,804	$14,757
2037	$86,211	$24,091	$15,536
2038	$88,631	$25,552	$16,473
2039	$90,885	$26,858	$17,243
2040	$93,594	$28,715	$18,552

Source: Environment Canada, 2015; NEB, 2016; Murillo, 2015; author calculations.

sands emissions. In the scenario where current emissions intensity levels were applied, the value of the unproduced oil begins at CA$1.19 billion (2015 dollars)[12] in 2025, increasing to CA$28.72 billion by 2040. The cumulative losses in this scenario from 2025 to 2040 total CA$254.74 billion, or approximately 22% of the potential CA$1.19 trillion of in-situ production that could occur between 2025 and 2040.

[12] All subsequent dollar values are in 2015 Canadian dollar terms.

The scenario where oil sands producers reduce their GHG emissions intensities allows for greater levels of production. Consequently, the value of unproduced oil is lower. In this scenario, the value of unproduced oil is CA$1.75 billion in 2027, but reaches CA$18.55 billion by 2040. Cumulative lost production value under this scenario totals CA$153.41 billion, or 13% of the total potential value of the in-situ oil.

In the first couple of years after the policy begins to affect production, the amounts of the lost value are modest compared to the total value of projected in-situ production, amounting to between 2% and 10%. However, as projected oil sands production continues to increase, losses begin to escalate, peaking in 2040 at approximately 30% (in the no emissions intensities reduction scenario) and 20% (in the emissions intensities reduction scenario) of the total projected value of in-situ production.

Oil sands emissions in a global context and the cost of abatement

Thus far, we have analyzed what the potential costs of the 100 Mt oil sands emissions policy could be in terms of potential lost production. This section analyzes the benefits of the policy in terms of mitigated CO_2-eq emissions and compares this to global emissions projections.

Table 5 presents the OECD's (2012) projections of global GHG emissions and our estimates of the emissions that could be averted as a result of the 100 Mt emissions cap policy. The table demonstrates that the potential emissions averted due to the policy change will be minimal in comparison to projected global emissions. To put this into perspective, in 2040, when the NEB projects oil sands production to be largest, meaning that emissions from production would also be greatest, the 100 Mt

Table 5: Comparision of Projected Global GHG Emissions and Emissions Averted Under the 100Mt Oil Sands Emissions Cap, Mt CO_2-eq

	Projected Global GHG Emissions	GHG Emissions Averted, No Emissions Intensity Reductions	GHG Emissions Averted, Emissions Intensity Reductions
2025	58,807	1	—
2026	59,518	4	—
2027	60,244	6	2
2028	60,980	8	4
2029	61,721	10	5
2030	62,492	12	6
2031	63,292	13	7
2032	64,108	15	9
2033	64,923	17	10
2034	65,724	18	11
2035	66,538	19	11
2036	67,441	21	12
2037	68,323	22	13
2038	69,203	22	13
2039	70,085	23	14
2040	70,974	25	15

Source: OECD (2012); author calculations

emissions cap policy could avert 25 Mt CO_2-eq emissions in a scenario with no efficiency reductions, and 15 Mt CO2-eq emissions in a scenario where the emissions intensity of oil sands production is reduced. Based on the OECD's (2012) projection of global emissions in 2040, Alberta's 100 Mt policy would result in a reduction of global emissions of 0.035% in the no emissions intensity reduction scenario, and a 0.021% reduction in global emissions based on

Table 6: Cost of the 100 Mt Emissions Cap Per Tonne of GHG Abated (in 2015 CA$)

	Cost per Tonne of GHG Abated, No Emissions Intensity Reductions	Cost per Tonne of GHG Abated, Emissions Intensity Reductions
2025	$863	—
2026	$891	—
2027	$919	$958
2028	$947	$990
2029	$976	$1,024
2030	$1,005	$1,058
2031	$1,021	$1,078
2032	$1,037	$1,098
2033	$1,053	$1,119
2034	$1,069	$1,140
2035	$1,086	$1,162
2036	$1,103	$1,184
2037	$1,120	$1,206
2038	$1,138	$1,228
2039	$1,155	$1,251
2040	$1,172	$1,273

Source: Authors' calculations.

the scenario where emissions intensity for oil sands extraction is reduced.

Indeed, if all production from Alberta's oil sands were halted, the resulting reductions in global emissions would still be quite minimal.[13]

The abated emissions will also come at a high cost. Table 6 presents the costs per tonne of

13 This of course does not consider that were the oil sands to stop producing completely, other oil producing regions around the world would likely make up for the reduction in production, thereby resulting in a smaller reduction in emissions.

GHG abated for the two emissions intensity scenarios. In the scenario with no emissions intensity reductions, the cost per tonne of abated GHG begins at CA$863 in 2025, increasing to $1,172 by 2040. The scenario where emissions intensity reductions occur has higher abatement costs than the scenario with no emissions intensity reductions due to the lower levels of GHG abatement. Starting in 2027, the cost of abating a tonne of GHG in the presence of emissions intensity reductions is $958. This compares to $919 in 2027 for the no intensity reduction scenario. By 2040, the cost of abating a tonne of GHG amounts to $1,273 when intensity reductions occur.

These costs of emissions abatement are well above those estimated by the US government and others. For example, consider the latest social cost of carbon (SCC) estimates produced by the US Government's Interagency Working Group on Social Cost of Carbon (IWG).[14] In their July 2015 update, the IWG estimated that the cost of an additional tonne of emissions in 2015, using a 3% discount rate,[15] was $41.[16] If a 5% discount rate is used, then the cost is $13 per tonne, and if a 2.5% discount rate is used then the cost is estimated to be $64 per tonne (IWG, 2015). Even as years progress and SCC estimates increase, they do not come close to reaching the estimated costs of abating a tonne of GHG through the 100Mt policy. By 2040, the IWG estimated the SCC to be $24, $69, or $96 depending on whether a 5%, 3%, or 2.5% discount rate is used.

Conclusion

This paper is a first step in attempting to quantify the effects of Alberta's 100 Mt emissions cap policy on future oil sands production and related GHG emissions. We found that the policy has the potential to reduce future oil sands production by a large amount but that the GHG emissions that could be averted would be minimal compared to projected global emissions. Furthermore, those averted emissions would come at a high cost to Canada. This analysis leads to serious questions about the imbalance of costs and benefits that result from the policy.

It is important to also view this framework in the broader context of future global oil and energy demand. As C. Peter Watson, chair and CEO of the NEB, recently noted in his forward to *Canada's Energy Future*:

> As long as there is demand for energy, markets will function to provide the supply, whether from domestic or international sources, with little consequential impact on global energy use and the associated emissions (NEB, 2016).

Policies that constrain the development of Canadian energy will only reduce the economic opportunity available to Canadians from the development of our resources. Policymakers should recognize this when devising policies that will affect the future development of Canada's energy resources. In particular, policymakers must carefully consider the costs and benefits of such policies. As evidenced above, the 100 Mt cap on GHG emissions appears to place large costs on Canadians by potentially constraining future growth in oil sands develop-

[14] The social cost of carbon is the estimated value of the damages associated with an additional unit of carbon.

[15] Discount rates are used to adjust future costs into present day values.

[16] IWG (2015) presented their estimates in 2007 dollars. The figures presented here have been adjusted to 2015 dollars.

ment, while providing little in the way of avoided GHG emissions.

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