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Enbridge Pipelines Inc. - Line 3 Replacement Program

Review of Related Upstream Greenhouse Gas Emissions Estimates

Draft for Public Comments

Executive Summary

This document provides an estimate of the upstream greenhouse gas (GHG) emissions associated with the Line 3 replacement project as well as a discussion of conditions under which the crude oil transported on a fully-utilized Line 3 project could be considered incremental production.

The Line 3 project proposes to replace sections of the existing Line 3 pipeline between Hardisty, Alberta, and Gretna, Manitoba, and involves the installation of new, and the replacement of existing, infrastructure (e.g. storage tanks, valves and pumps) as well as the decommissioning of the existing pipeline. The design average annual capacity of the new pipeline (760,000 barrels per day) represents a return to the original design capacity of the Line 3 pipeline from its current capacity of 390,000 barrels per day.

Environment and Climate Change Canada estimates that the upstream GHG emissions in Canada associated with the production and processing of crude oil transported by the Line 3 project could be between 19 and 26 megatonnes of carbon dioxide equivalent per year. This represents the upstream emissions associated with the design average annual capacity of the Line 3 project (760,000 barrels per day) and does not distinguish between the upstream emissions associated with the current capacity of Line 3 (390,000 barrels per day) and the upstream emissions associated with the additional pipeline capacity that would be enabled by this project (370,000 barrels per day). The estimated emissions are not necessarily incremental; the degree to which the estimated emissions would be incremental depends on the expected price of oil, the availability and costs of other transportation modes (e.g., crude by rail), and whether other pipeline projects are built.

For crude oil producers, investment decisions are driven by the expected price of oil. Incremental production is more likely to be enabled by increased pipeline capacity when long-term oil prices are in a range between $60-80 per barrel (2013 U.S. dollars). At prices higher than this range, many oil sands projects would be profitable even if transporting crude oil by rail was the only option. Therefore, incremental production is less likely to be enabled by increased pipeline capacity at higher oil prices. If long-term oil prices were expected to be lower than around $60 per barrel (2013 U.S. dollars), significant new investment in oil sands production may not be expected regardless of the mode of transportation (i.e., rail or pipeline). However, Environment and Climate Change Canada acknowledges the challenges associated with attributing any incremental GHG emissions to a specific pipeline given that a number of pipeline projects with similar construction timelines and capacities have been proposed in Canada.

Given the global competition for investment in oil production, it is likely that if oil sands production did not occur in Canada, investments would be made in other jurisdictions and global oil production and consumption would be materially unchanged. As a result, the difference in global GHG emissions arising from any increase in Canadian crude oil production would be the difference in upstream emissions, including extraction, refining and transportation between oil sands production and a comparable crude oil. Oil sands production growth is expected to be comprised primarily of diluted bitumen blends, a heavy oil, and this analysis assumes that the end market for that crude oil with or without the Line 3 project is the U.S. Gulf Coast. Other heavy crude oils that are major sources of supply for U.S. Gulf Coast refineries have similar emission intensities to Canadian heavy crude oils.

Introduction

As part of its January 27, 2016 announcement of interim principles, the Government of Canada has committed to undertake an assessment of upstream greenhouse gas (GHG) emissions associated with projects undergoing an environmental assessment.[1] Environmental assessments of projects already include an assessment of the direct emissions caused by a project.

The following assessment of upstream GHGs for the Enbridge Pipelines Inc. (Enbridge) Line 3 Replacement Program includes a project description, a quantitative estimation of the GHG emissions released as a result of upstream production associated with the project (Part A), and a discussion of the project's potential impact on Canadian and global GHG emissions (Part B).

Project Description

Enbridge`s Line 3 pipeline (Line 3) is an existing 863.6 millimeter (mm) -diameter, 1,600- kilometer (km) pipeline between Edmonton, Alberta and Superior, Wisconsin.[2] Line 3 is part of a larger Enbridge Mainline system (Mainline) that includes Lines 1, 2, 3, 4, 13, and 67.[2] The Mainline system enables crude oil, natural gas liquids and refined petroleum product transportation from the hub in Edmonton, Alberta, to locations in Canada and further south into the U.S.[3] Since it began operating in the late 1960s, the annual average capacity of Line 3 has varied between an original design average annual capacity in the range of 760,000 bbl/d and its current low of 390,000 barrels per day (bbl/d) resulting from operating conditions including voluntary pressure restrictions put in place by Enbridge to ensure the continued safe operation of the pipeline.[4]

On November 5, 2014, Enbridge submitted an application for the Line 3 Replacement Program to the National Energy Board (NEB).[4] The project (Line 3 project) proposes to replace sections of the existing 1,066-km pipeline between Hardisty, Alberta, and Gretna, Manitoba, and includes:[5]

- the replacement of the existing Line 3 (863.6 mm) pipeline with a new (914.4 mm) pipeline;
- the addition of remotely operated sectionalizing valves;
- the replacement of Line 3 pumps and associated infrastructure and equipment;
- the addition of tankage at the Hardisty Terminal; and
- the decommissioning of the existing Line 3 pipeline.

Based on Enbridge's application to the NEB, if constructed, the Line 3 replacement pipeline can be expected to operate at Line 3's original design average annual capacity of 760,000 bbl/d. This represents an additional throughput of 370,000 bbl/d when compared to the current capacity of Line 3. The project description indicates that the pipeline could transport light, medium and heavy crudes.[6] The application also indicates that in the absence of this project, it is expected that Enbridge will continue to operate Line 3 at its current capacity.

If approved, the projected in-service date for the replacement pipeline is expected to be early 2019.

The Line 3 project will enhance the Mainline's capacity to deliver crude oil to markets in Ontario, Quebec, and the Midwestern U.S.[7] Enbridge is also pursuing the expansion of pipelines entirely in the United States: Lines 1 (Sandpiper Expansion/Bakken Interconnect Idle), 2 (Flanagan South, Seaway), and 61 (Southern Access Project). Midwestern pipeline connections in the US would enable greater access to southern U.S. crude oil markets, including the U.S. Gulf Coast, which offers an expanded market for Canada's growing crude oil production.[8]

The operation and construction-related GHG emissions have been assessed by the proponent and reviewed by the NEB. These emissions will not be considered as part of this assessment.

Part A: Estimation of the Upstream GHG Emissions

Part A of the assessment provides quantitative estimates of the GHG emissions released as a result of upstream extraction and processing of crude oils associated with the project. For the purposes of this review, *upstream emissions* are emissions from the extraction and processing of crude oils prior to their injection in the Line 3 project. This includes emissions from combustion, industrial processes, flaring, venting, and fugitive sources. The GHG emissions from these sources contain carbon dioxide, methane and nitrous oxide. These constituents of GHG emissions were added together taking into account their respective global warming potentials. The scope of this assessment does not extend to indirect upstream emissions, such as those related to land-use changes and those generated during the production of purchased inputs including equipment, grid electricity and fuels. Those emissions have only been considered if they are not distinguishable from the direct upstream emissions. Emissions related to the transportation of crude oils from a facility to Line 3 were also not considered but are expected to be minor when compared to other upstream emission sources associated with the project.

The quantitative estimates developed for this assessment represent the upstream GHG emissions associated with the various crude oils that could be transported in Line 3. The methods used to extract and process the different crude oils may vary and as a result have different levels of GHG emissions associated with their extraction and processing activities. As well, the crude oil mix[i] may change during the operational life of the pipeline project to reflect operational requirements and market demand. Due to the potential variability associated with the crude oil mix, including relative volumes and types of crude oil transported through the Line 3 project, results are presented for several potential scenarios.

Project Throughput

For the purposes of Part A of the assessment, it is assumed that the Line 3 project would operate at its design average annual capacity of 760,000 bbl/d once it is placed into service. Whether or not the upstream GHG emissions estimated to be associated with this throughput could result in incremental GHG emissions in Canada is not discussed in Part A. A discussion of the implications on Canada's GHG

[i] The proportion of different categories of crude oil (such as diluted bitumen or conventional light crude oil) carried in the pipeline over time is the crude oil mix.

emissions of the additional pipeline capacity (370,000 bbl/d) that this project could bring to the existing Line 3 capacity (390,000 bbl/d) is included in Part B.

Project Crude Oil Mix

The proponent has indicated that the project will be able to transport all types of crude oil produced in the Western Canada Sedimentary Basin (WCSB). For the purposes of this assessment, it is assumed that the many different types of crude oil produced from the WCSB can be aggregated into six categories based on their extraction methods and their density:

Conventional Light This includes low density crude oil streams that flow through wells and pipelines without processing or dilution.

Conventional Heavy This includes high density crude oil streams that flow through wells and pipelines without processing or dilution.

CSS Heavy This includes high density crude oil streams produced using Cyclic Steam Stimulation (CSS). In this *in situ* method, steam is injected into a heavy crude oil reservoir. This introduces heat that thins the oil and allows it to be produced. Production involving the addition of solvent with steam is also included.

SAGD Heavy This includes high density crude oil streams produced using Steam-Assisted Gravity Drainage (SAGD). In this *in situ* method, a pair of horizontal wells is used. High pressure steam is injected into the upper well to heat the oil and reduce its viscosity, causing the heated oil to drain into the lower well, where it is pumped out. Production involving the addition of solvent with steam is also included.

Mined Bitumen This includes high density crude oil streams that originate from surface mining of bitumen-containing deposit and processing to extract bitumen. The bitumen is then blended with light petroleum products (such as condensate) to become diluted bitumen.

Synthetic This includes low density crude oil streams produced by upgrading high density crude oil.

Based on the NEB's *Estimated Canadian Crude Oil Exports by Type and Destination*, it is estimated that Line 3 presently transports a crude oil mix of 30% conventional light and 70% synthetic crude oils.[9] In the future, the production of heavy oil using CSS, SAGD, and mining extraction methods are projected to account for a higher proportion of the overall Canadian production. The Line 3 project will be capable of transporting a range of crude oil types from the WCSB. Three potential crude oil mixes were therefore considered for this assessment and form the basis of the scenarios modeled to estimate upstream GHG emissions. Table 1 provides the proportions of each crude oil category described above for the three crude oil mixes.

Table 1 – Crude Oil Mixes

Crude Oil Category	Present Mix (%)	Historic Mix (%)	Future Mix* (%)
Conventional Light	30	20	14
Conventional Heavy	0	6	18
CSS Heavy	0	2	8
SAGD Heavy	0	15	22
Mined Bitumen	0	5	8
Synthetic	70	53	29

* *The future crude oil mix reflecting the WCSB production varies year over year based on the NEB reference case. The Future Mix for **2019** is presented here as an example. The data for all the years of the modelling period (2019-2030) is included in Annex C*.

Emission Scenarios

Using combinations of the three crude oil mixes presented above, ECCC estimated emissions for four different scenarios to assess a range of upstream emissions that could be associated with the project.

Scenario 1

In this scenario, the crude oil mix is assumed to be the *Present Mix*: 30% conventional light crude oil and 70% synthetic crude oil. The pipeline is assumed to be operating with a throughput at the design average annual capacity of 760,000 bbl/d. Both the crude oil mix and the pipeline throughput do not vary throughout the modelling period (2019-2030).

Scenario 2

In this scenario, the crude oil mix is assumed to be the *Future Mix*. The respective proportions of the different crude oil categories vary throughout the modelling period, and are presented in Annex C. The pipeline is assumed to be operating with a throughput at the design average annual capacity of 760,000 bbl/d throughout the modelling period (2019-2030).

Scenario 3

In this scenario, the current capacity of the pipeline (390,000 bbl/d) is expected to transport the *Present Mix*: 30% conventional light crude oil and 70% synthetic crude oil. The additional capacity of 370,000 bbl/d resulting from the project is expected to transport the *Historic Mix*: 53% synthetic crude oil, 20% conventional light crude oil, 15% heavy crude oil extracted with SAGD, 6% conventional heavy crude oil, 5% mined bitumen, and 2% heavy crude oil extracted with CSS. Both the crude oil mix and the pipeline throughput do not vary throughout the modelling period (2019-2030).

Scenario 4

In this scenario, the crude oil mix is assumed to be the *Historic Mix*: 53% synthetic crude oil, 20% conventional light crude oil, 15% heavy crude oil extracted with SAGD, 6% conventional heavy crude oil, 5% mined bitumen, and 2% heavy crude oil extracted with CSS. The pipeline is assumed to be operating with a throughput at the design average annual capacity of 760,000 bbl/d. Both the crude oil mix and the pipeline throughput do not vary throughout the modelling period (2019-2030).

The resulting range of estimated upstream GHG emissions for the Line 3 project is presented below in Table 2 for the four scenarios described above. The methodology used to determine these emission estimates is described in the *GHG Forecast Approach* section below.

Table 2- Upstream Emissions Estimates for the Four Scenarios (Mt of CO_2 eq)

Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2019	25.8	20.2	24.4	23.2
2020	25.9	20.2	24.5	23.3
2021	26.0	20.2	24.6	23.3
2022	26.0	20.1	24.7	23.4
2023	26.1	20.0	24.7	23.4
2024	26.1	19.8	24.7	23.3
2025	26.1	19.7	24.7	23.4
2026	26.1	19.6	24.7	23.3
2027	26.1	19.5	24.7	23.3
2028	26.1	19.5	24.6	23.3
2029	26.1	19.4	24.6	23.2
2030	26.1	19.3	24.6	23.2

As illustrated in Table 2, the estimates of upstream GHG emissions are significantly influenced by the assumed crude oil mix that will be transported by the project. There is uncertainty in the actual crude oil mix that will be transported by the Line 3 project and therefore, the actual associated upstream GHG emissions. As well, this part of the assessment (Part A) does not consider whether these emissions would occur in the absence of the project. Given these inherent uncertainties, the values presented are estimates of a range of possible upstream GHG emissions associated with the project.

ECCC projects that the upstream GHG emissions in Canada associated with the production and processing of crude oil transported by the Line 3 project could range from 19.3 to 26.1 Mt of CO_2 eq per year.

GHG Forecast Approach

The estimates are calculated using GHG emission projections from ECCC's recently published *Canada's Second Biennial Report on Climate Change* submitted to the United Nations Framework Convention on Climate Change (UNFCCC)[10] as well as the NEB's production projections.[11] For the Line 3 project estimates, ECCC used the details of the projected GHG emissions and productions that were specific to the *current measures* reference scenario.[10] This reference scenario includes actions taken by governments, consumers and businesses up to 2013, as well as the future impacts of existing policies and measures that have been put in place as of September 2015. The projections do not reflect the impact of additional federal, provincial or territorial measures that were announced since September

2015 or that are still under development. A number of recently announced provincial government policies, such as those outlined in Alberta's *Climate Leadership Plan,* will have an impact on Canadian GHG emissions, but were not reflected in *Canada's Second Biennial Report on Climate Change* as the details of these policies were not available at the time of publication. Alberta's *Climate Leadership Plan* includes a commitment to cap emissions from oil sands facilities at 100 Mt in any year, reduce methane emissions from oil and gas operations by 45% by 2025, set performance standards for large industrial emitters, and apply a carbon levy to fuels. British Columbia has announced that it will be updating its *Climate Leadership Plan* and has recently concluded public consultations. Other provinces are also planning new actions that will have implications for oil and gas sector emissions. In addition, on March 3, 2016, First Ministers adopted the *Vancouver Declaration on Clean Growth and Climate Change*, in which they commit to develop a concrete plan to achieve Canada's international climate commitments and become a leader in the global clean growth economy. As these plans get defined and take effect, they will be incorporated in future emissions projections and future upstream GHG assessments.

The details of ECCC's GHG projections provide emissions and production forecasts according to specific crude oil categories. The emissions include emissions resulting from combustion, industrial processes, flaring, venting, and fugitive sources that are associated with the extraction and processing activities of these crude oil categories. The GHG emissions from these sources include carbon dioxide, methane, and nitrous oxide, where these constituents of GHG emissions are added together taking into account their respective global warming potentials.

For the purposes of this assessment, ECCC developed emission factors representing the relative upstream emissions contributions per unit volume of crude oil category. Each categories of crude oil that may enter the pipeline has a specific emission factor that depends on the emissions generated during its extraction and upgrading, when this occurs.

In order to develop emission factors ECCC divided projected emissions for extraction and upgrading, as appropriate, by the respective production projection. The resulting emission factors are presented in Table 3.

The throughput for each crude oil category was determined by taking into account the project's expected throughput and expected crude oil mix. Each crude oil category's throughput was adjusted (where applicable) to exclude the diluent portion associated with transporting that category of crude oil.

The total diluent volume moving through the pipeline also has upstream emissions associated with its production. Most of the diluent is expected to be imported according to the NEB report *Canada's Energy Future 2016* (*NEB Futures*). Upstream emissions are only estimated for the portion of the diluent that is expected to be produced in Canada. The emission factors for conventional light crude oil were used for the diluent portion that is produced in Canada.

Table 3 - GHG Emission Factors (kg of CO_2 eq/barrel)

Year	Conventional Light	Conventional Heavy	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2019	68.5	59.0	82.3	75.1	44.1	103.3
2020	68.7	58.6	82.4	75.4	44.2	103.7
2021	69.0	58.2	82.4	75.8	44.4	104.1
2022	69.2	57.7	82.4	76.1	44.6	104.5
2023	69.3	57.2	82.4	76.1	44.7	104.6
2024	69.4	56.7	82.4	76.1	44.7	104.6
2025	69.5	56.4	82.4	76.1	44.7	104.9
2026	69.6	56.2	82.4	75.9	44.7	104.8
2027	69.7	55.9	82.5	75.8	44.7	104.7
2028	69.7	55.6	82.6	75.5	44.7	104.5
2029	69.8	55.4	82.7	75.4	44.7	104.4
2030	69.8	55.1	82.8	75.3	44.7	104.4

The emission factors in Table 3 were then multiplied by the adjusted throughput of each crude oil category moving through the Line 3 project. The sum of the calculated emissions from each crude oil category expected to move through the pipeline is the estimated upstream emissions for the project. Emissions estimates were developed for each year, starting at the expected start date of the project and up to the end of the forecast period (2030).

Part B: Impacts on Canadian and Global Upstream GHG Emissions

Introduction

Part A presents estimates for a range of upstream GHG emissions that could be associated with the production and processing of crude oil products transported on the project. However, given that there are multiple transportation modes available for crude oil, it is possible that a portion of the emissions calculated in Part A would occur with or without the Line 3 project, or, for that matter with or without additional pipeline capacity more generally.

If oil production were expected to occur in the absence of the project, the pipeline project would not be enabling incremental oil production and would therefore have no impact on upstream GHG emissions. If, however, the oil production would not occur in the absence of the project, but would only occur if the project was built, then there would be incremental upstream emissions. Given that incremental oil production will lead to incremental GHG emissions, these terms are used interchangeably here.

Part B discusses the conditions under which the production of the oil volumes on a fully-utilized Line 3 project would be incremental. Part B focuses on the additional volumes (+370,000 bbl/d) of crude oil that could be transported on a fully-utilized Line 3 project rather than the emissions associated with all of the oil (760,000 bbl/d) transported on the pipeline. This part assumes that if the Line 3 project did not proceed, Enbridge would continue to operate the pipeline at its current rate in the future (390,000 bbl/d), which is consistent with Enbridge's regulatory filings with the NEB. Several limitations of this discussion are provided in Annex A.

Part B is divided into four sections. The *Canadian Oil Production Outlook* section discusses the NEB's and ECCC's projections for future oil production and upstream GHG emissions growth, and a discussion of Canada's climate commitments in relation to oil sands production growth. The *Pipeline and Rail Infrastructure* section discusses crude-by-rail movements and capacity in North America, and compares the economics of crude-by-rail versus pipelines. The *Incremental Emissions* section outlines scenarios in which pipeline capacity additions could enable incremental production, and important considerations related to global oil consumption and GHG emissions. The *Conclusions* section outlines the key findings of the analysis.

Canadian Oil Production Outlook

This section discusses the NEB's projections of Canadian oil production growth, and the constrained pipeline case from the *NEB Futures* report. It then discusses GHG emissions projections made by ECCC, potential markets for Canadian crude oil, and oil market uncertainties. The section concludes with a discussion of Canada's GHG commitments and their potential implications for Canadian oil sands growth.

Canadian Oil Supply Growth

In 2015, Canada produced an estimated 3.9 million barrels per day (MMbbl/d) of crude oil, of which 2.4 MMbbl/d, or approximately 61%, was from the oil sands. According to the reference scenario in the *NEB Futures* report, oil production in Canada is expected to increase by nearly 58% and reach 6.1 MMbbl/d of production by 2040. The NEB estimates that 79% (or 4.8 MMbbl/d) of this amount will come from the oil sands, and that this will be largely composed of bitumen production from *in situ* operations. The remainder of oil sands growth is expected from mining operations, with only a small increase in upgraded bitumen. Projected growth in oil sands production under the reference case represents a doubling by 2040 from 2014 levels (See Figure 1).[12] Most production forecasts, including the NEB's reference, high price, and low price scenarios, assume pipeline capacity will be built as required.

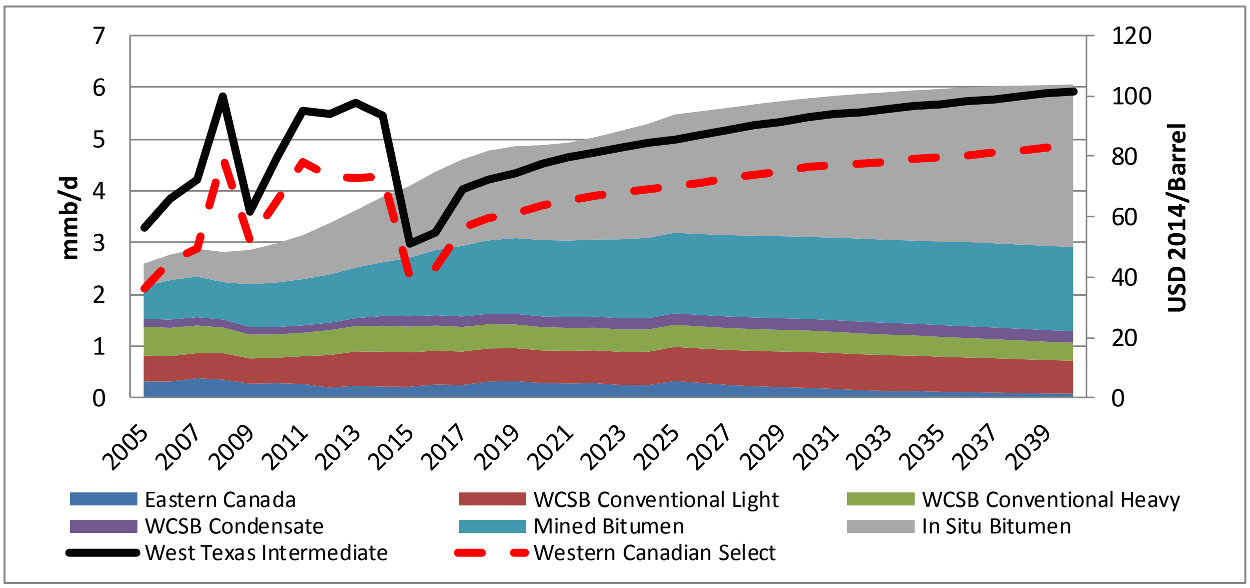
Given that most production growth will be comprised of bitumen, crude oil transported on any additional pipeline capacity in the future will likely be largely comprised of diluted bitumen (dilbit) blends from Western Canada. This conclusion informs the discussion throughout Part B.

In the *NEB Futures* reference case, the price of West Texas Intermediate (WTI) – a North American crude oil benchmark – averages USD $51 ($2014) per barrel of oil (bbl) in 2015, increasing to USD $78/bbl in 2020, and finally reaching USD $102/bbl by 2040. Western Canadian Select (WCS), the benchmark heavy crude oil from western Canada, is priced USD $17/bbl lower than WTI over the projection period.

NEB Futures also examines low and high oil price scenarios and the impacts of such prices on Canadian crude oil production. In the low price scenario, the WTI crude oil price is on average USD $26/bbl ($2014) lower than the reference case, reaching USD $80/bbl by 2040. In the high price scenario, the WTI crude oil price is on average USD $26/bbl higher than the reference case, reaching USD $134/bbl by 2040. In the low price scenario, oil sands production grows marginally after projects under construction are completed, and reaches 3.8 MMbbl/d in 2040, approximately 21% lower than the reference case. In the high price scenario, oil sands production reaches 5.3 MMbbl/d in 2040, approximately 6% higher than the reference case. [11]

Despite the current low oil price environment, the NEB expects that most production growth in the oil sands up to 2020 will remain unaffected. However, projects with completion dates in the longer term, or projects that have not started construction, are likely to see delays and deferrals if oil prices stay low.[11] Other forecasts have also noted that most supply growth to the end of the decade can be considered 'locked in', and is unlikely to be reduced by a significant amount. ECCC estimates around 576,000 bbl/d of oil sands capacity is expected to finish construction and come online between 2016 and 2019 (see Annex B).[ii]

Figure 1 – Total Canadian Crude Oil and Equivalent Production and Oil Price Forecast (Reference Case)



Source: NEB, Canada's Energy Futures 2016

NEB Constrained Pipeline Case

As part of the *NEB Futures*, the NEB examines a scenario which illustrates the potential impacts of a constrained oil transportation system. The NEB constrained case assumes that no major proposed export pipelines (e.g. Keystone XL, Northern Gateway, Trans Mountain Expansion, and Energy East) are

[ii] Much of the estimated 576,000 bbl/d of capacity under construction is bitumen production which would need to be diluted with a light hydrocarbon to be transported on a pipeline. Assuming a 30% diluent blend (70% bitumen) for in situ projects and a 20% diluent blend for bitumen mines, the figure increases to 720,000 bbl/d of pipeline grade oil sands production.

built; however, the Line 3 project is completed. As such, this case assumes that the Enbridge Mainline expansions (including Line 3) and crude-by-rail are the only options available to transport Canadian crude oil production growth. Further, the NEB analysis, like this report, assumes that the primary growth market for Canadian exports of heavy crude from the oil sands is the U.S. Gulf Coast (see section on North American Markets for Oil Sands Production Growth).

Constrained pipeline capacity leads to transportation costs that are higher than what they otherwise would be in the reference case. For example, the price differential between WCS and WTI grows by USD $10/bbl relative to the reference case, representing the incremental cost to transport crude on rail to the U.S. Gulf Coast. These lower prices lead to lower cash flow, lower investment, and ultimately to lower oil production in 2040 in the constrained scenario relative to the NEB's reference case.

In this constrained case, Canadian oil production continues to grow, albeit with a time lag of around five years (2020-2025) where oil production growth effectively ceases. Delayed projects and reduced investment results in Canadian oil production being approximately 0.5 MMbbl/d (or 8%) lower than the reference case, dropping from 6.1 MMbbl/d to 5.6 MMbbl/d in 2040. As would be expected, oil sands production is affected the most since this is where most production growth occurs in the reference case.

Canada's GHG Emissions Projections

ECCC projects that Canada's total annual GHG emissions will rise to 815 Mt in 2030 from 726 Mt in 2013, under its reference or *with current measures* scenario as reported in *Canada's Second Biennial Report on Climate Change* submitted to the United Nations Framework Convention on Climate Change (UNFCCC).[10] This scenario is based on historical data and actions taken by governments, consumers and businesses up to 2013, as well as the estimated future impacts of existing policies and measures that have been put in place as of September 2015 (without taking into account the contribution of the land use, land-use change and forestry sector). A number of recently announced provincial government policies, such as those outlined in Alberta's *Climate Leadership Plan,* will have an impact on Canadian GHG emissions, but were not reflected in *Canada's Second Biennial Report on Climate Change* as the details of these policies were not available at the time of publication. Alberta's *Climate Leadership Plan* includes a commitment to cap emissions from oil sands facilities at 100 Mt in any year, reduce methane emissions from oil and gas operations by 45% by 2025, set performance standards for large industrial emitters, and apply a carbon levy to fuels. British Columbia has announced that it will be updating its *Climate Leadership Plan* and has recently concluded public consultations. Other provinces are also planning new actions that will have implications for oil and gas sector emissions. In addition, on March 3, 2016, First Ministers adopted the *Vancouver Declaration on Clean Growth and Climate Change*, in which they commit to develop a concrete plan to achieve Canada's international climate commitments and become a leader in the global clean growth economy. As these plans get defined and take effect, they will be incorporated in future emissions projections and future upstream GHG assessments.

The growth in emissions to 2030 is driven largely by growth in the upstream oil and gas sector and, in particular, from the oil sands. ECCC projections indicate that GHG emissions from the oil sands could increase from 62 Mt in 2013, to 90 Mt in 2020 and up to 116 Mt in 2030. Emissions from oil sands *in situ* projects are expected to increase by 40 Mt between 2013 and 2030 while GHG emissions from bitumen mining and upgrading operations are projected to increase by 10 Mt and 5 Mt, respectively, between 2013 and 2030.[10]

North American Markets for Canadian Oil Sands Production Growth

The U.S. is divided into five petroleum markets termed Petroleum Administration Defense Districts (PADDs): PADD I (East Coast); PADD II (U.S. Midwest); PADD III (U.S. Gulf Coast); PADD IV (Rocky Mountain), and; PADD V (West Coast, AK, HI).[8] The Line 3 project would increase pipeline capacity to PADD II (U.S. Midwest).This report assumes that PADD III is the ultimate destination for increased volumes of crude oil transported on pipelines to PADD II due to[iii]:

1) The fact that PADD II is already a major consumer of Canadian crude and has limited capacity to further increase refining of heavy oil volumes, barring future refinery upgrades;
2) The connections to other pipelines within PADD II that move oil to Cushing, Oklahoma and, ultimately, PADD III, and;
3) The expected growth in heavy oil production in Canada and the substantial amount of heavy oil refining capacity in PADD III.

PADD II is the second largest refining market in the U.S. and the largest market for Canadian crude oil. In 2014, refineries in PADD II processed 3.5 MMbbl/d of oil which represented 23% of U.S. crude oil consumption (see Table 4).[13] In addition, PADD II refineries use large volumes of heavy oil as inputs. In 2014, refineries in PADD II processed 1.3 MMbbl/d of heavy oil, or about 31%, of all U.S. heavy oil refinery inputs, and of this, 1.1 MMbbl/d was heavy Canadian crude oil. Exports to PADD II accounted for 71% of all Canadian heavy oil exports in that year. [13iv]

Both the NEB and the Canadian Association of Petroleum Producers (CAPP) have noted that refineries in PADD II have little scope to process more heavy oil, largely driven by the growth in light tight oil production from the U.S. that has reduced the expected profitability of further refinery conversion projects.[8,11] As such, growth in Canadian oil sands production is more likely to be transported to other markets than PADD II.

PADD III includes refineries in the U.S. Gulf Coast and is one of the largest refining markets in the world. In 2014, refineries in PADD III processed 8.3 MMbbl/d of crude oil.[13,8] PADD III is the largest U.S. market for heavy crude oil, processing approximately 2.2 MMbbl/d, or 52% of heavy crude in the U.S. in 2014. Despite being a major market for crude oil, in 2014, PADD III refineries sourced only 2%, or 0.2 MMbbl/d, of their crude oil inputs from Canada. PADD III is a competitive market as refineries have access to various types of crude oil due to tidewater access and their proximity to major pipeline hubs. Mexico and Venezuela are key suppliers of crude oil to PADD III, supplying 1.4 MMbbl/d (18%) of total crude consumed in 2014.[8,11]

[iii] This report acknowledges that expanding the pipeline system can change the composition of crude oil on specific pipelines and that the Line 3 project could be used to transport crude oil that is currently being produced. As such, its construction could shift barrels onto Line 3, enabling more heavy oil to flow on other pipelines.

[iv] Heavy oil is defined to include both heavy conventional crudes and oil sands bitumen, but there are varying definitions. For instance, the NEB defines heavy oil as any crude with an API gravity less than 25 degrees, while CAPP defines heavy as any crude with an API gravity below 28 degrees.

Table 4 – U.S. Refining Capacity, Oil Receipts, and Canadian Exports by PADD in 2014

	Total Refinery Crude Oil Receipts		Total Refinery Heavy Oil Receipts		Canadian Exports of Bitumen and Heavy Oil	
	MMbbl/d	% of Total	MMbbl/d	% of Total	MMbbl/d	% of Total
PADD I (East Coast)	1.09	7%	0.15	4%	0.09	6%
PADD II (Midwest)	3.52	23%	1.29	31%	1.13	71%
PADD III (Gulf Coast)	8.25	53%	2.16	52%	0.13	8%
PADD IV (Rocky Mountains)	0.25	2%	0.17	4%	0.17	10%
PADD V (West Coast)	2.4	15%	0.37	9%	0.07	4%
U.S. Total	**15.51**		**4.14**		**1.59**	

Source: CAPP (2015) forecast based on U.S. Energy Information Administration Data and NEB.

PADD V, Ontario and Quebec were also considered for this analysis, but these markets had either less scale or less ability to process heavy oil under current refinery configurations. In the future, companies could invest in these regions to process more Canadian heavy crude; however, the timeline for such investments is uncertain.

Oil Market Uncertainties

Oil Prices

WTI crude oil prices have declined 76% over the past two years, from a high of USD $107/bbl in June 2014 to as low as USD $26/bbl in February 2016. Primary factors contributing to the recent decline in world oil prices are the increase in North American unconventional crude oil production, slower economic growth in emerging markets, and the decision by the Organization of the Petroleum Exporting Countries (OPEC) to maintain output levels in the face of these developments. At current prices (as of March 2016), many Canadian oil and gas companies are posting losses and companies are reducing spending on longer-term projects, rather than those that are in the later stages of construction. For example, the NEB reported that over 700,000 bbl/d of oil sands capacity has been cancelled or delayed in recent years, most with start-up dates in the post-2020 timeframe.[14]

Pipeline Constraints

Increasing production from U.S. light tight oil and from Canada's oil sands caused pipeline bottlenecks in North America in recent years with consequences for crude oil prices, in particular, price differentials between inland North American crude oil benchmarks and international benchmarks.

In a market without infrastructure constraints, the differences between benchmark prices should largely reflect differences in crude oil quality and transportation costs. However, between 2011 and 2014, WCS crude traded at an average discount to Maya (a similar quality crude oil) of USD $21.50/bbl, more than triple the 2007-2010 average of USD $6.40/bbl.[10] Pipeline constraints and resulting price differentials caused many companies to invest in crude-by-rail capacity between 2012 and 2014 (discussed below).

At this time, many pipelines from the WCSB are at, or nearing, their effective capacities as evidenced by the many pipelines under apportionment.[v] Current pipeline projects, including the Line 3 project, that have been proposed to and/or approved by the NEB have a cumulative capacity of over 3.4 MMbbl/d.[8]

Canadian Climate Change Commitments and Oil Sands Production

In December 2015, Canada and 194 other countries reached the Paris Agreement at the UNFCCC's 21st Conference of the Parties (UNFCCC's COP21). Under this agreement, countries committed to the long-term goal to limit average temperature rise to well below 2°C and pursue efforts to limit the increase to 1.5°C. Under the UNFCCC, Canada committed to a target of reducing emissions 30% below 2005 levels by 2030.

A number of studies have considered scenarios where global warming is limited to 2°C. However, these scenarios utilize different modelling frameworks and can have vastly different assumptions around technological and economic progress. The role of technological innovation, policy design and stringency, and consumer and business behaviour, both in Canada, and globally, can have significant implications on Canadian oil sands production in these scenarios. As a result of the differing treatment of these variables, conclusions across scenarios are not uniform, and the impact on Canadian oil sands production is not clear. However, a common result of modelling efforts to analyze a 2°C world is that overall global crude oil consumption declines relative to the status quo.

Some studies have presented scenarios where oil sands production growth is not fully consistent with a world in which global warming is limited to 2°C. For example, a 2014 study found that Canadian bitumen production could increase to 4.1 MMbbl/d in 2035 and be consistent with a 2°C target, but only with a rapid deployment and scale-up of carbon capture and storage (CCS) technology from 2020 and the decarbonization of energy inputs.[15] In a 2015 study with a longer timeframe for analysis, the same authors found that, even with widespread CCS deployment from 2025, Canadian oil sands production would be significantly curtailed. The authors concluded that 74% of Canadian crude oil reserves would have to remain unexploited to be consistent with a 2°C target and estimated that, without CCS, all bitumen production in Canada would have to cease by 2040 to be consistent with a 2°C target.[16]

Other projections show that oil sands production could continue to expand from current levels while still limiting warming to 2°C: for example, the International Energy Agency's (IEA) World Energy Outlook's 450ppm scenario.[17] The IEA's 2014 World Energy Investment Outlook concludes that most non-OPEC crude oil reserves (including Canada's oil sands) could be produced in a 2°C world.

A recent report by Carbon Management Canada concluded that Canada's 2030 reductions target is one of several possible emissions reduction pathways consistent with a 2°C objective. The report assumes the significant innovation of currently unknown technology, and highlights the importance of low carbon

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[v] In its fourth quarter 2015 Management's Discussion and Analysis, Enbridge Energy noted that the Mainline pipeline network remained under apportionment and was expected to be so into 2016. Apportionment occurs when the total desired amount of crude oil transportation space exceeds the available shipping capacity for that type of crude oil on a pipeline. The space on a pipeline under apportionment is rationed between bidding parties, typically on a pro-rata basis.[v] The gap in pipeline takeaway capacity from the WCSB is expected to increase to the end of the decade with the expected growth in oil sands production.

extraction techniques for the oil sands and carbon capture and storage for Canada's decarbonisation aspirations.[18]

As noted above, the variations in these findings are driven by different modelling frameworks and assumptions around the future energy mix and rates of technological progress. It is not yet clear what policy frameworks will be put into place globally, and it is extremely challenging to predict which technologies may be commercialized in the future. Given the difficulties in predicting these variables, the analysis in this report uses a forecast based on the NEB that incorporates current policies and commercialized technologies. Over time, new technologies and policies will be developed that will change the emissions intensity and economic feasibility of oil production both in Canada and globally, as well as act to change the attractiveness of alternatives to oil.

Pipeline and Rail Infrastructure

For crude oil production to grow in the absence of pipeline development there must be a viable transportation alternative. Companies are expected to pursue new oil production opportunities if they can earn the required rate of return on investment, regardless of the mode of transport. In the case of crude-by-rail, the conditions for new oil production are:

i. Sufficient crude-by-rail capacity exists or can expand to meet demand, and;
ii. Project economics under future oil price expectations remain sufficiently attractive when shipping crude-by-rail.

It is worth noting that when transporting oil similar distances, rail has been generally recognized as being more emissions intensive than transporting oil by pipeline. As a result, in the absence of the project, if crude is transported via rail, this transportation option may result in higher direct transportation emissions. In their assessment of the Keystone XL Pipeline, the U.S. State Department found that direct operating GHG emissions were approximately 42% higher when comparing transporting oil by rail instead of pipe.[19] The differential is highly dependent on the emission intensity of the electricity used to operate the pipeline's pumps. In areas with high grid average electricity emission intensity, the differential could be smaller while in areas with lower grid average electricity emission intensity, the differential could be larger.

This section begins with a discussion of crude-by-rail movements and capacity in North America, and ends with a comparison of the economics of crude-by-rail versus pipelines.

North American Crude-by-Rail Loading & Offloading Infrastructure

There have been questions surrounding whether rail infrastructure could support significant crude-by-rail growth (e.g., a sufficient supply of tanker cars, the costs associated with enhanced safety regulations and requirements for crude-by-rail transportation, etc.). However, growth has been strong to date, and there is historical precedent for such growth. For example, the U.S. State Department's *Final Supplemental Environmental Impact Statement for the Keystone XL pipeline* (KXL FSEIS) outlines the growth of rail transport from a coal basin as a precedent for the possibility of rapid railway expansion.[20]

Crude-by-rail loading capacity from the WCSB has expanded significantly in the past five years. While traditionally it was employed primarily by smaller crude oil producers, crude-by-rail has served as an alternative for companies in recent years as pipeline constraints and price differentials increased. Estimates indicate that crude-by-rail loading capacity in Alberta and Saskatchewan is over 1.0 MMbbl/d, with an effective loading capacity greater than 0.8 MMbbl/d.[10,vi] In the U.S., crude-by-rail offloading capacity is concentrated in PADD I and PADD III and estimated at over 1 MMbbl/d in these markets. PADD II has around 50% of total U.S. crude loading capacity, at 1.2 MMbbl/d.[20]

Crude-by-rail capacity figures are not directly comparable with pipeline capacity figures. When bitumen is produced, the extracted bitumen is either upgraded to synthetic crude oil (typically production from oil sands mines) or blended with a diluent to enable the heavy crude oil to flow on a pipeline. The volume of diluent blend can vary, but is typically around 30% of a barrel of diluted bitumen (dilbit). For dilbit, since the diluent is blended with the bitumen for transport, producers also pay to ship the associated diluent to market, reducing the amount of pipeline space available for bitumen.

Rail cars can haul oil sands blends with a lower proportion of diluent. Reducing the amount of diluent in the oil sands blend decreases rail transportation costs per barrel of bitumen and any losses from the difference in diluent value between the origin and destination markets.[21] Alternative bitumen blends hauled on rail are railbit (15-20% diluent) or rawbit (0-2% diluent). Transporting rawbit requires special tanker cars and loading and offloading facilities, which are not widely used at this time.[21]

North American Crude-by-Rail Movements

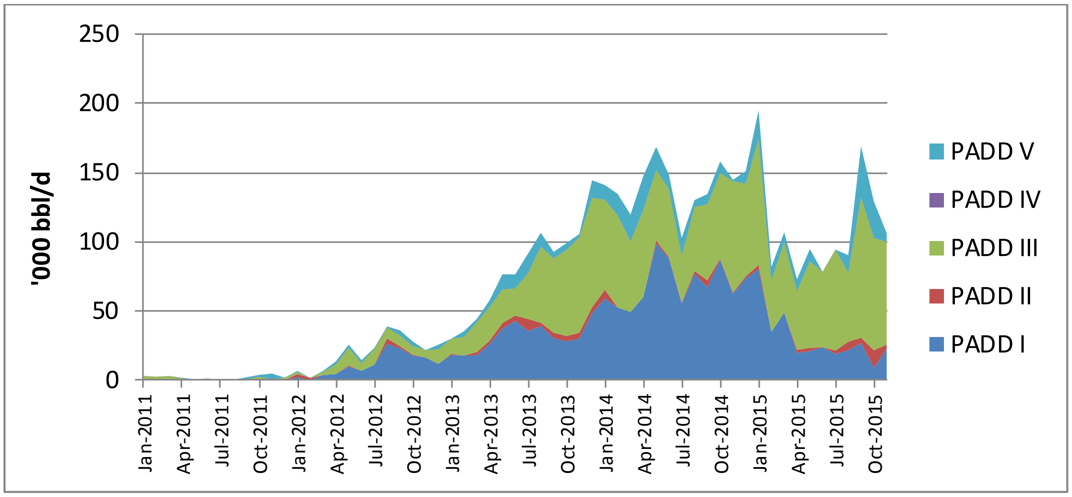
Since 2011, exports of crude oil by rail from Canada to the U.S. have increased substantially, from an average of just under 2,000 bbl/d in 2011 to over 107,000 bbl/d in 2015. Crude-by-rail export volumes peaked at 195,000 bbl/d in January 2015, and declined to under 110,000 bbl/d in late 2015.[22] While crude-by-rail exports from Canada were initially spread fairly evenly between PADDs I and III, the destination for exports shifted towards PADD III in 2015. These figures do not include crude-by-rail volumes transported within Canada (Figure 2).

Canadian crude-by-rail is not solely for export. Several Canadian refineries and ports have installed or expanded crude-by-rail offloading capacity including Suncor's Montreal refinery (35,000 bbl/d of rail offloading capacity), Valero's Levi refinery (60,000 bbl/d), Irving's St. John refinery (200,000 bbl/d), Chevron's Burnaby refinery (7,000 bbl/d) and the Sorel-Tracey terminal in Quebec (33,000 bbl/d).

Crude-by-rail use grew even more quickly in the U.S. where expansion was driven by production growth in remote regions which were underserved by pipelines. For example, crude-by-rail movements from PADD II (the U.S. Midwest) increased from an average of 90,000 bbl/d in 2011 to 640,000 bbl/d in 2015 as a result of tight oil production growth from the Bakken fields in North Dakota. Overall, the increases in crude-by-rail movements in North America show the market's ability to address pipeline constraints.

[vi] The Department of State Final Supplemental Environmental Impact Statement (KXL FSEIS) Market Analysis notes a report from the Industrial Commission of North Dakota (2013) that cites effective rail capacity at around 80% of nameplate capacity. The NEB's *Canada's Energy Futures 2016* report recently noted that estimated crude-by-rail loading capacity in Western Canada was "over 1 MMbbl/d".

Figure 2 - Canadian Crude-by-Pipeline Exports by PADD, monthly 2011-2015



Source: U.S. EIA (2016) Crude Oil Movements of Crude Oil by Rail

Relative Costs of Pipelines and Rail

The cost difference between crude oil pipelines and rail is the primary consideration as to whether the construction of additional pipeline capacity could result in greater crude oil production, and therefore greater upstream GHG emissions in Canada. If rail costs are sufficiently high relative to pipeline transportation costs, the return on future projects required to use rail would be expected to decline and these projects may not be built in the absence of new pipelines. As noted above, the report assumes that the primary market for Canadian production growth would be PADD III, the U.S. Gulf Coast.

In *NEB Futures*, the NEB estimates that the cost difference between shipping a barrel of bitumen to the U.S. Gulf Coast on rail and shipping via pipelines would be USD $10/bbl.[22] This is consistent with the KXL FSEIS which estimated a cost difference of up to USD $9/bbl (depending on the diluent content). This is an upper threshold since the relative cost of rail would decrease if a company reduced the amount of diluent blended with the bitumen or had negotiated lower rates of transport via rail. The KXL FSEIS estimated that the additional cost to rail "rawbit" was between USD $0-3/bbl relative to pipelines while the additional cost to transport "railbit" was between USD $5-7/bbl relative to pipelines. Also, it is important to consider that these cost estimates do not incorporate tax or royalty considerations, which would decrease the relative difference in transportation costs in after-tax terms.

Even with a cost difference, there are some advantages to rail including greater flexibility in destinations and shorter transport times. Other benefits are discussed in CAPP's 2015 crude oil forecast.[8]

Incremental Emissions

This section provides a discussion of the conditions under which Canadian oil sands production growth, and its associated upstream emissions, could be higher if the Line 3 project were built then if it were not. It considers two pipeline scenarios: 1) no additional pipeline capacity from 2015 capacity levels is built besides the Line 3 project, and 2) other additional pipeline capacity as well as the Line 3 project is built such that shipping large volumes of crude-by-rail is no longer needed.[vii] The baseline to compare to each of these scenarios would be one in which no additional pipeline capacity would be added and any production growth would be expected to be shipped by rail.

Baseline

Under the baseline, no new pipeline capacity is built and oil production currently transported via rail (~100,000 bbl/d of exports) or under construction (~576,000 bbl/d of capacity) will be transported via rail. Further oil production growth is possible, but all future production will be transported via rail. If future projects are expected to be sufficiently profitable when transporting oil-by-rail, they will proceed in the baseline.

Scenario 1: Line 3 Replacement is the only new pipeline capacity built

As discussed previously, it is considered likely that production growth from oil sands projects already under construction would continue as planned. In a scenario in which the Line 3 project was built, but no other pipeline capacity from the WCSB was built, some portion of this production growth (~576,000 bbl/d) and/or some portion of crude export volumes on rail would likely shift to the additional pipeline capacity (370,000 bbl/d) available on the Line 3 project. Under these circumstances, none of the barrels transported on the Line 3 project, and their associated upstream GHG emissions, would be incremental or attributable to the pipeline since this production growth would have occurred regardless of whether the Line 3 project was built. In this scenario, large-scale oil transportation by rail will be required to get oil to markets both before and after the completion of the Line 3 project since the Line 3 project is only expected to add 370,000 bbl/d of capacity and 'locked in' production growth is greater than this amount.

Scenario 2: Line 3 Replacement and other pipeline capacity is built

If the Line 3 project and other pipelines are built such that large-scale rail shipments of crude oil were no longer needed, then the additional pipeline capacity (Line 3 project and others) could reduce transportation costs for producers relative to the baseline. Under this scenario, additional pipeline capacity could enable production growth, and therefore greater upstream GHG emissions relative to the baseline. However, attributing any particular portion of these incremental upstream emissions to the Line 3 project, or any specific pipeline project, would be difficult.

To understand the degree to which additional pipeline capacity could support greater production (beyond that which is already under construction), it is necessary to examine the financial viability of new investments in the oil sands.

Supply Costs for Oil Sands Projects

Analysts often use a metric referred to as the supply cost to compare and assess the financial feasibility of proposed projects. For oil sands projects, this is the constant dollar price of oil that is required to recover all capital and operating costs, taxes, and royalties, and earn a rate of return on investment

[vii] Some volumes may still flow by rail under this scenario, but it is assumed that this would be for reasons related to small producers not being able to achieve economies of scale for pipeline access.

(usually 10-15%).[11] For ease of comparison, supply costs are usually adjusted to a benchmark crude oil hub, such as WTI or Brent, and reported in U.S. dollars.

A survey of various sources that regularly publish oil sands supply cost estimates reveals a range of estimates for oil sands projects with key differences in supply costs driven by the type of project (in situ vs. mining) and the modelling assumptions.[23, 24, 25] *In situ* project supply costs range between USD $45/bbl and $80/bbl WTI-equivalent while mine project supply costs range between $80/bbl and $90/bbl WTI equivalent.[viii] The lower end of the range typically represents expansions at existing facilities and the higher end represents new projects. Key differences in supply costs result from assumptions around exchange rate, energy use, capital costs, and price differentials.

Oil Sands Supply Costs and Additional Costs from Crude-by-Rail

Wood Mackenzie estimates that a large number of planned but unsanctioned *in situ* projects (i.e., projects where the company has not given investment approval), with a potential capacity of up to 800,000 bbl/d, have supply costs between USD $50-70/bbl on a WTI-equivalent basis assuming pipeline transportation (see Figure 3). Based on the incremental cost estimates above (+$10/bbl), it is expected that the supply cost range for a large amount of planned projects post-2020 would increase to between USD $60-80/bbl if producers had to use rail.

Low Prices

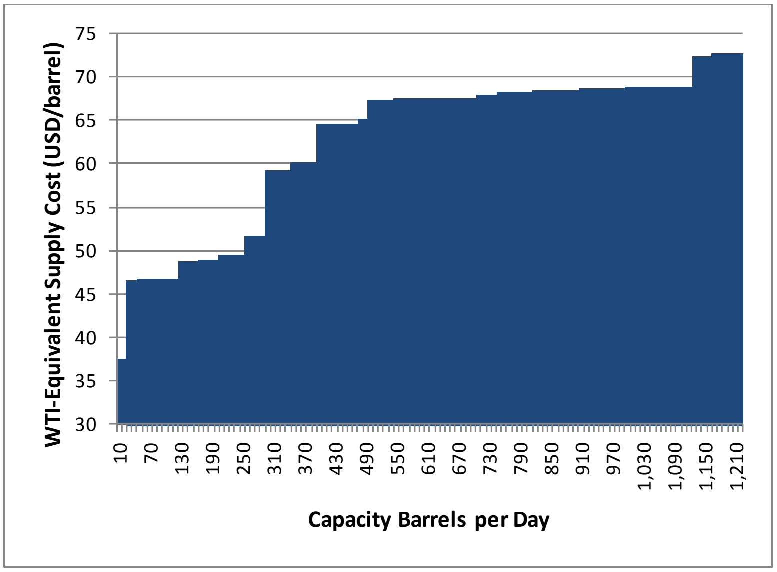
If long-term WTI prices were below USD $60/bbl in real terms, there is unlikely to be substantial oil sands production growth. An example of this low growth is the *NEB Futures* low price scenario discussed above that has prices growing to only USD $60/bbl by 2025, and only USD $76/bbl by 2040. In this case oil production only grows by approximately 150,000 barrels per day after projects currently under construction are completed (i.e. after 2020), even when pipeline capacity is available. Given the challenged project economics at such prices, it is not expected that the availability of pipeline transportation would improve profitability sufficiently such that a company would decide to proceed. As a result, if prices were in this range, it is considered unlikely that the completion of the Line 3 project would cause incremental upstream GHG emissions that would not have otherwise occurred in the baseline scenario.

Mid-Range Prices

If long-term WTI oil prices were between USD $60 and $80/bbl in real terms, the cost savings that arise from the ability to transport crude via pipeline could enable oil production growth that would not have otherwise occurred in the baseline scenario.

[viii] Integrated mining projects are not discussed in this piece because few new integrated mining projects are planned at this time.

Figure 3 - Oil Sands Supply Curve for Unsanctioned *In Situ* Projects, assuming pipeline transportation



Source: Wood Mackenzie

All else being equal, between these prices and assuming transport by rail, supply cost estimates indicate that a considerable amount of planned but unsanctioned oil sands production capacity could become profitable (~800,000 bbl/d) that may not have been profitable when rail was the only transportation option in the baseline. As defined previously, any production that would not have occurred in the baseline scenario, but may occur if the Line 3 project is completed, is considered to result in incremental upstream GHG emissions. To the degree to which incremental rail costs are lower than $10/bbl, the amount of incremental production and associated incremental upstream GHG emissions, if any, would be less due to more attractive project economics as well as higher revenues and investment. Therefore, if long-term oil prices were to be in this range some production growth could be incremental.

That being said, the Line 3 project is one of many proposed pipeline projects in the medium term. Other pipeline projects are proposed with timelines that are not substantially different from those of the Line 3 project, and such construction projects are often delayed. Therefore potential incremental upstream GHG emissions, if any, that could occur under this scenario because of additional pipeline capacity are not easily attributable to any specific pipeline.

High Prices

If longer term WTI oil prices were greater than USD $80/bbl in real terms, a number of projects would likely already be expected to be strongly profitable and a large amount of oil sands growth would be expected to occur regardless of whether the oil was moved by pipeline or rail. However, upstream project economics would be further improved if pipeline transportation options were available at higher oil prices. As put forward under the NEB's constrained case, the cost savings provided by pipelines could result in increased cash flow available for re-investment and, over time, increased production which would likely increase upstream GHG emissions compared to a case where production would be transported via rail. In reality, this effect may be minimal given the availability of capital in global financial markets. As such, less production is expected to be incremental than when prices are between USD $60 and $80/bbl.

Other Considerations

Given the significant number of oil sands projects that could become economic in the USD $60-80/bbl range there is greater potential for incremental production resulting from pipeline construction if long term prices were in that range (see Table 5).

Table 5 - Potential Incremental Oil Sands Production in Canada

	Price		
	<$60	**$60-80**	**>$80**
Oil Sands Growth	Limited to no growth in oil sands production	Limited growth in oil sands production	Growth in oil sands production
Incremental GHG Emissions as a result of pipelines	Unlikely	Potential	Minimal
Potential cumulative oil sands supply with a supply cost in the price range (post-2020)	~0.25 MMbbl/d	~1.05 MMbbl/d	~1.15 MMbbl/d

Source: Wood Mackenzie
***Wood Mackenzie does not model all proposed projects**

The Wood Mackenzie data does not include all potential oil sands projects and, therefore, potential production growth in the future could be higher than the planned capacity noted above. The Alberta Energy Regulator, in their ST-98 report on Alberta's Energy Reserves 2014 and Supply/Demand Outlook 2015-2024, lists all projects currently under construction, application, and that have received approval. Excluding projects under construction, the AER counts nearly 2.7 MMbbl/d of potential new *in situ* production, and 1.0 MMbbl/d of potential new mining production. While substantial new production capacity has been submitted for regulatory approval, it is unlikely that all these projects will go forward in the next decade given recent reductions in spending and cash flow and the significant capital and labour requirements that would be associated with moving this scale of new production forward.

Global Oil Consumption and Upstream GHGs

Many global supply curves illustrate that oil sands projects have supply costs that are broadly comparable to alternative sources of oil supply. For example, in an analysis of future oil projects that have not received a final investment decision, Wood Mackenzie showed that oil sands projects are similar in cost to 13 MMbbl/d of other types of production. In an analysis of the 420 largest global oil projects, Goldman Sachs expects nearly 30 MMbbl/d of crude oil production capacity with supply costs in the range of USD $40-80/bbl.

Given the many competitors to an investment in Canadian oil production, it is likely that if oil sands production were to not occur in Canada, investments would be made in other production opportunities. Similar heavy crude oils include Mexican Maya and Venezuelan which, as noted above, are major sources of crude to the U.S. Gulf Coast. As a result, global oil production would likely be materially unchanged in the long-term as a result of the approval of a pipeline project in Canada. As such, the difference in global GHG emissions from any increase in Canadian crude oil production would be the difference in emissions from upstream production, refining, and transportation between oil sands production and a comparable crude oil. [ix]

IHS reports the relative lifecycle GHG emissions from various global crude oils.[26] A key finding from this report was that nearly half of the types of crude oil consumed in the U. S. are within the same GHG intensity range as those from the Canadian oil sands. The report also notes that the most likely substitute for Canadian oil sands at U.S. refineries is Venezuelan crude oil which has a GHG intensity within the same range as the Canadian oil sands. As such, if global oil consumption remains constant, with or without the Line 3 project, the difference in global GHG emissions would be expected to be minimal.

Conclusions

The analysis in Part B provides insight into the conditions under which building the Line 3 project could lead to incremental GHG emissions in Canada. The key elements affecting this discussion are the expected long-term price of crude oil, oil sands supply costs, the availability and relative cost of crude-by-rail, and assumptions around total pipeline capacity that could be built. In summary, the discussion finds that:

- *If the Line 3 project is the only additional pipeline capacity added from Western Canada,* oil sands production already expected to be completed by 2019, as well as volumes currently transported by rail, would be more than sufficient to fill the proposed Line 3 project. Under this scenario, it is likely that the upstream emissions calculated in Part A would occur regardless of whether the Line 3 project was built or not.
- *If additional pipeline capacity is built such that shipping crude-by-rail was no longer needed*, a portion of the emissions calculated in Part A could be incremental. The degree to which pipeline capacity enables incremental production depends on the long-term oil price and the differences in transportation costs between rail and pipelines. However, it would be difficult to attribute these incremental upstream emissions to the pipeline capacity added by the Line 3 project.
    - At WTI prices lower than USD $60/bbl, most planned oil sands projects not yet under construction would likely be unprofitable and would not be built regardless of transportation mode. There is unlikely to be incremental emissions under these prices.
    - At WTI prices of USD $60-80/bbl, many planned projects that would not be profitable if rail were the only transportation option could become profitable with pipeline access. However, the amount of incremental production is uncertain.

[ix] A recent assessment of the GHG impacts of the Energy East pipeline found that the pipeline could be expected to have an impact on global crude oil prices and, therefore, global consumption.

   - At higher WTI prices of greater than USD $80/bbl, many planned oil sands projects would be profitable and have a higher likelihood of being built, even if rail were the only transportation option. However, the cost savings provided by pipelines could result in some increased investment and production, although incremental production would likely be less than if oil prices were in the USD $60-80/bbl range noted above.
- Given the competition for investment in oil production, it is likely that if oil sands production were to not occur in Canada, investments would be made in other jurisdictions and global oil consumption would be materially unchanged in the long-term in the absence of Canadian production growth. Given that other types of heavy crude oils with similar emission intensities are major sources of supply for the U.S. Gulf Coast, the difference in global GHG emissions from any increase in Canadian crude oil production would be the difference in emissions from upstream production, refining, and transportation between oil sands production and a comparable crude oil.

Annex A – Limitations of the Analysis

There are a number of limitations with the approach taken to discuss whether the construction of the Line 3 project could enable more crude oil production and, therefore, upstream GHG emissions, than a case in which no additional pipeline capacity was built. These include:

- The data and sources used in this report are limited to those that are publicly available. For example, some specifics around supply costs and performance of oil sands projects are estimates based on third-party analysis. ECCC has vetted these sources to the greatest degree possible and plans to enrich this data in the future, but recognizes that there may be competing estimates from other sources.

- This analysis relies primarily on data and projections from the Government of Canada, including the NEB's *Canada's Energy Future 2016* document for production projections. It is important to consider that the NEB's forecast includes only policies and programs that are law at the time of writing are included in the projections. Any new policies under consideration, or new policies developed after the summer of 2015 are not included. Impacts of the project on oil markets, prices or production were not modelled for this analysis as this report is intended as a discussion of the *conditions* under which additional pipeline capacity would support greater crude oil production, and upstream GHG emissions, relative to a case in which no new pipeline capacity was built. Sophisticated modeling approaches have been employed by third parties for other pipelines, such as the study on the Energy East pipeline proposal undertaken by Navius Research for the Ontario Energy Board. However, undertaking such work is outside of the scope of this analysis.

Annex B – Oil Sands and Heavy Oil Projects Under Construction (2015)

Type	Company	Project	Status	Planned capacity (bbl/d)	Estimated Start-up
In Situ	Brion Energy	Mackay River Phase 1	Construction	35,000	2016
In Situ	Cenovus/ConocoPhillips	Foster Creek Phase G	Construction	30,000	2016
In Situ	Cenovus/ConocoPhillips	Christina Lake Phase F	Construction	50,000	2016
In Situ	Japan Canada	Hangingstone Expansion	Construction	20,000	2016
In Situ	Husky Energy	Edam East & West	Construction	14,500	2016
In Situ	Husky Energy	Vawn	Construction	14,500	2016
In Situ	Sunshine Oil Sands	West Ells	Construction	5,000	2016
Mining	Canadian Natural Resources	Horizon Phase 2/3	Construction	137,000	2017
Mining	Suncor/Total/Teck	Fort Hills Phase 1	Construction	180,000	2017
In Situ	Cenovus/ConocoPhillips	Foster Creek Phase H	Construction delayed[x]	30,000	2018
In Situ	Cenovus/ConocoPhillips	Christina Lake Phase G	Construction delayed[6]	50,000	2018
In Situ	Harvest Operations Corp	BlackGold Phase 1	Steaming delayed[xi]	10,000	2018
Total under construction or expected				**576,000**	

Source: IHS, 2015; CanOils (2016); Company Reports

[x] According to IHS, Cenovus has stated that it will continue to advance two projects simultaneously through the low price period. It will first complete Foster Creek Phase G and Christina Lake Phase F before resuming construction on Foster Creek Phase H and Christina Lake Phase G expansions of these facilities. Cenovus had also commenced early construction at its Narrow Lake project, but in light of comment, it will likely advance only after prices are higher.

[xi] IHS notes that the project is complete, but Harvest has stated that steaming will not commence until prices rise above $60 per barrel WTI.

Annex C – Proportion of Each Product Included in the Future Mix for the 2019-2030 Period

Year	Conventional Light (%)	Conventional Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)
2019	15	18	8	22	8	29
2020	15	18	8	23	7	29
2021	14	17	8	24	7	29
2022	14	17	8	25	7	28
2023	14	17	8	26	7	28
2024	14	16	9	27	7	27
2025	14	15	9	28	8	27
2026	14	15	9	29	8	26
2027	14	15	9	29	8	26
2028	14	15	9	30	8	25
2029	13	15	9	31	7	25
2030	13	14	9	31	7	25

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