Environment and Climate Change Canada
Environnement et Changement climatique Canada

Trans Mountain Pipeline ULC - Trans Mountain Expansion Project

Review of Related Upstream Greenhouse Gas Emissions Estimates

Draft for Public Comments

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Canada

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Executive Summary

This document provides an estimate of the upstream greenhouse gas emissions (GHG) associated with the transportation capacity on the Trans Mountain Expansion project, and a discussion of conditions under which the crude oil transported could be considered incremental production[i].

The Trans Mountain Expansion project proposes to expand the existing Trans Mountain pipeline system between Edmonton (Alberta) and Burnaby (British Columbia) by increasing its nominal capacity from the current 300,000 barrels per day to 890,000 barrels per day. The project would involve the construction of a new pipeline that would effectively twin the existing pipeline through Alberta and British Columbia, the addition of new pump stations and storage tanks, and the construction of a new dock at the Westridge Marine Terminal in Burnaby (British Columbia).

Environment and Climate Change Canada estimated the upstream GHG emissions in Canada associated with the production and processing of crude oil and refined products transported by the expanded Trans Mountain pipeline. The GHG emissions projections and production projections used by Environment and Climate Change Canada for this assessment include the estimated future impacts of existing policies and measures that have been put in place as of September 2015. A number of important measures to reduce GHG emissions from the oil and gas sector have been announced since September 2015 but are not reflected. As measures are defined and take effect, they will be incorporated into future emissions projections and future upstream GHG assessments.

Once completed, the upstream GHG emissions associated with the entire Trans Mountain pipeline system, transporting 890,000 barrels per day, could be between 20 and 26 megatonnes of carbon dioxide equivalent per year. Considering only the 590,000 barrels per day capacity added by the expansion project, the upstream GHG emissions could range from 14 to 17 megatonnes of carbon dioxide equivalent per year. 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 along with other considerations, including costs of production and transportation to markets.

If the Trans Mountain Expansion 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 project. Under this scenario, it is likely that the upstream emissions calculated in this assessment would occur regardless of whether the project was built or not.

If additional pipeline capacity, including the Trans Mountain Expansion project, is built such that shipping crude-by-rail was no longer needed, a portion of the emissions noted above could be

[i] In the context of this assessment, the word *additional* is used when discussing the added capacity that the project would bring. The word *incremental* is used when discussing the production (and resulting emissions) that could be directly enabled by this project.

incremental. Incremental production is more likely to be enabled by increased pipeline capacity when long-term Canadian light oil prices are in a range between $60-80 per barrel (2015 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 Canadian light oil prices were expected to be lower than around $60 per barrel (2015 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). In addition, 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 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. As a result, the difference in global GHG emissions arising from any increase in Canadian crude oil production would be the difference in emissions from upstream production, refining, and transportation between Canadian oil sands production and a comparable crude oil, often referred to as differences in well-to-tank emissions. A survey of available data indicate that the well-to-tank emissions from oil sands *in situ* diluted bitumen are within the same range as other types of heavy crude oil currently used in the Pacific market. This indicates that the impact on global emissions of increased Canadian oil sands diluted bitumen reaching global markets depends on the mix of crude oil being displaced by Canadian diluted bitumen.

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.

This assessment of upstream GHGs for the Trans Mountain Expansion (TMX) project includes a project description, a quantitative estimation of the GHG emissions released as a result of upstream production associated with the expanded Trans Mountain pipeline (Part A), and a discussion of the project's potential impact on Canadian and global GHG emissions (Part B).

On March 19, 2016, Environment and Climate Change Canada (ECCC) published its proposed methodology to estimate upstream GHG emissions associated with major oil and gas projects undergoing federal environmental assessments in the *Canada Gazette,* Part I (2). This proposed methodology is applied in this assessment.

Project Description

In operation since October 1953, the Trans Mountain pipeline was built to supply crude oil to locations in Canada and in the United States (U.S.). The initial capacity was 150,000 barrels per day (bbl/d) with four pump stations along the line and a marine loading dock. Since 1953, the capacity of the pipeline system has been increased a number of times.

The current Trans Mountain pipeline is approximately 1,147 kilometers (km) long, beginning in Edmonton, Alberta, and terminating on the west coast of British Columbia, in Burnaby. Twenty-three pump stations located along the pipeline route maintain the 300,000 bbl/d capacity of the line. In addition to the pump stations, five terminals located in Edmonton, Kamloops, Abbotsford (Sumas terminal) and Burnaby (Burnaby terminal and Westridge Marine terminal) serve as locations for incoming feeder pipelines and tanker loading facilities (3):

Edmonton Terminal	Reception of crude oil and refined products
Kamloops Terminal	Delivery of refined products for local use and reception of crude oil from northeastern British Columbia
Sumas Pump Station / Terminal	Routing of crude oil to either the Puget Sound pipeline system for delivery to Washington State refineries, or to the Burnaby terminal
Burnaby Terminal	Delivery of crude oil to the Chevron refinery or refined products to the Suncor products terminal
Westridge Marine Terminal	Delivery of crude oil for shipping

On December 16, 2013, Trans Mountain Pipeline ULC submitted an application for the TMX project to the National Energy Board (NEB). The TMX project would expand the existing Trans Mountain pipeline system between Edmonton and Burnaby, increasing its nominal capacity from the current 300,000 bbl/d to 890,000 bbl/d. The TMX project would include (4):

- construction of 987 km of new 914.4 millimeter (mm) outside diameter buried pipeline (in three segments) that would twin the existing pipeline through Alberta and British Columbia, as well as two new 3.6 km long buried delivery lines from the Burnaby terminal to the Trans Mountain Westridge Marine Terminal;
- new and modified facilities, including the addition of 12 new pump stations and 18 new storage tanks;
- reactivation of 193 km of existing 609.6 mm outside diameter pipeline (in two segments) and the existing Niton pump station, as well as adding one pumping unit at the existing Sumas pump station;
- deactivation of some elements at the existing Wolf and Blue River pump stations; and
- construction of a new dock with three new berths at the Westridge Marine Terminal (the existing berth would be decommissioned).

The TMX project would also require ancillary facilities as well as power lines and permanent access roads. Some temporary infrastructure would also be required during construction. Trans Mountain plans to begin construction in 2017 and put the expanded pipeline into service in 2019.

The operation and construction-related GHG emissions have been assessed by the proponent and the NEB. In their Environmental and Socio-Economic Assessment, the proponent has estimated operational GHG emissions of the expanded Trans Mountain pipeline to be 407 kilotonnes (kt) per year of carbon dioxide equivalent (CO_2 eq) at full build (5). 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, processing, and refining of crude oil that could be associated with the total capacity of the expanded Trans Mountain pipeline. 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 oil and refined products from facilities to the expanded Trans Mountain pipeline were also not considered, but are expected to be minor when compared to other upstream emission sources associated with the project.

The extraction, processing, and refining of the different crude oils may vary; as a result, different crude oils may have different levels of GHG emissions. In addition, the types of crude oil and refined product (i.e. product mix[i]) that could enter the pipeline will change during its operational life to reflect operational requirements and market demand. Due to the potential variability associated with the product mix transported by the expanded Trans Mountain pipeline, emissions estimates are presented for several potential scenarios.

A.1 Project Throughput

For the purposes of Part A of the assessment, it was assumed that the expanded Trans Mountain pipeline would operate with a throughput equal to its expanded nominal capacity of 890,000 bbl/d[ii] starting in 2020. This assumption was kept constant throughout the modelling period (2020-2030). Whether or not the estimated upstream GHG emissions 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 emissions of the additional pipeline capacity (+590,000 bbl/d) that this project could bring to the existing pipeline capacity (300,000 bbl/d) is included in Part B[iii].

A.2 Product Mix

For the purposes of this assessment, the many different types of crude oil and refined products that could be transported by the expanded Trans Mountain pipeline were aggregated into the following seven product categories. The product categories have been selected to allow for the use of emissions data from ECCC (6) and production trends from the NEB (7) to develop emissions factors (see section A.5 below).

Refined Products This includes alkylate, diesel, gasoline, iso-octane, and Jet A turbine fuel. These products are derived from crude oil through refining processes such as catalytic cracking and fractional distillation.

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. A transportation dilution fraction of 8% was assumed for the purposes of this assessment.

CSS Heavy This includes high density crude oil streams extracted 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 extracted. A transportation dilution fraction of 30% was assumed for the purposes of this assessment. Extraction involving the addition of solvent with steam is also included.

[i] The proportions of different categories of products (such as diluted bitumen or refined products) carried in the pipeline over time is the product mix.
[ii] Pipelines do not necessarily operate at full capacity on a continuous basis and therefore the estimates presented in this assessment represent the maximum upstream emissions that could be associated with the project for a given product mix.
[iii] In the context of this assessment, the word *additional* is used when discussing the added capacity that the project would bring. The word *incremental* is used when discussing the production (and resulting emissions) that could be directly enabled by this project.

SAGD Heavy This includes high density crude oil streams extracted 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. A transportation dilution fraction of 30% was assumed for the purposes of this assessment. Extraction 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. A transportation dilution fraction of 20% was assumed for the purposes of this assessment. This category does not include mined bitumen upgraded to synthetic cure oil, which falls into the *Synthetic* category below.

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

A.3 Product Mix Scenarios

ECCC estimated emissions for four different product mix scenarios to assess a range of upstream GHG emissions that could be associated with the expanded capacity of the Trans Mountain pipeline. The respective proportions of the product categories for each scenario are presented in Annex A.

The following assumptions are common to all four scenarios, and are derived from information submitted by Trans Mountain to the NEB:

- The throughput of *Refined Products* was kept constant at 44,000 bbl/d throughout the modelling period.
- The throughput of *Conventional Light* crude oil originating from British Columbia entering the Trans Mountain system at the Kamloops terminal was kept constant at 12,500 bbl/d throughout the modelling period.

For Scenarios 2, 3 and 4 the product mix was derived from a report by the RWDI corporation, submitted as part of Trans Mountain's application for the TMX project (8). The report presents the expected throughput of products (receipts and deliveries) at each loading/unloading point along the expanded Trans Mountain pipeline. As an intermediate step, ECCC grouped the product categories from the report into *heavy crude oil*, *light sour crude oil*, *light sweet/synthetic crude oil*, and *refined products* categories, and made the following assumptions that are common to Scenarios 2, 3 and 4.

- The 58,000 bbl/day of *light sour crude* oil identified in the report was kept constant throughout the modeling period.
- The proportions of various heavy products (listed in A.2 above) that make up the intermediate *heavy crude oil* category (*Conventional Heavy, SAGD Heavy, CSS Heavy and Mined Bitumen*) were derived using data from the NEB, and they vary throughout the modelling period (7).

A.3.1 Scenario 1

For this scenario, the product mix was derived from a report by the Muse Stancil & Co. corporation submitted as part of Trans Mountain's application for the TMX project (9). This report presents estimates of the disposition of western Canadian crude oil (expressed as *blend types*[iv]) to various locations. For this scenario, the *Puget Sound / Burnaby* and *Northeast Asia* disposition locations were selected since, on the Trans Mountain system, crude oil is routed at the Sumas terminal to either the Puget Sound pipeline system, or to the Westridge Marine Terminal. The correspondence between *blend types* and the product categories used in this assessment was obtained using generic data on blend type composition obtained from the NEB[v] and the Alberta Energy Regulator[vi].

A.3.2 Scenario 2
In this scenario the *light sweet/synthetic crude oil* intermediate category was split into *Synthetic* products and *Conventional Light* products, and the proportions of each were derived using data from the NEB which vary throughout the modelling period (7).

A.3.3 Scenario 3
In this scenario the *light sweet/synthetic crude oil* intermediate category was assumed to include only *Synthetic* products.

A.3.4 Scenario 4
In this scenario the *light sweet/synthetic crude oil* intermediate category was assumed to include only *Conventional Light* products.

As an example, Table 1 provides the proportions of each product category for the scenarios described above, for year 2020.

Table 1: Product Mixes

Product Category	Scenario 1 (%)	Scenario 2 (%)	Scenario 3 (%)	Scenario 4 (%)
Refined Products	5	5	5	5
Conventional Light	18	17	8	34
Conventional Heavy	1	18	18	18
CSS Heavy	10	8	8	8
SAGD Heavy	8	24	24	24
Mined Bitumen	37	10	10	10
Synthetic	22	18	26	-

A.4 Estimated Upstream GHG Emissions

The resulting range of estimated upstream GHG emissions associated with the expanded nominal capacity, in megatonnes of carbon dioxide equivalent per year (Mt of CO_2 eq), 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.

[iv] *Blend types* are specific crude oil blends made from different types of crude oil in order to achieve specific crude oil properties (e.g. density and acidity)
[v] Personal communication, NEB
[vi] Statistical Reports ST39 and ST53

ECCC projects that the upstream GHG emissions in Canada resulting from the production, processing, and refining of products associated with the entire transportation capacity of the expanded Trans Mountain pipeline could range from 20.3 to 25.7 Mt of CO_2 eq per year. Considering only the additional 590,000 bbl/d capacity that this project is adding to the Trans Mountain pipeline system, emissions could range from 13.5 to 17.0 Mt of CO_2 eq per year.

As illustrated in Table 2, the estimates of upstream GHG emissions are significantly influenced by the assumed product mix that will be transported by the project. There is uncertainty in the actual product mix that will be transported by the expanded Trans Mountain pipeline 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 expanded Trans Mountain pipeline.

Table 2: Upstream Emissions Estimates for the Three Scenarios (Mt of CO_2 eq)

Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2020	24.0	22.8	23.8	20.8
2021	24.3	22.8	23.8	20.8
2022	24.3	22.7	23.8	20.7
2023	24.3	22.6	23.6	20.6
2024	24.8	22.5	23.6	20.5
2025	25.7	22.5	23.5	20.5
2026	25.2	22.5	23.5	20.5
2027	24.2	22.4	23.5	20.5
2028	24.3	22.4	23.4	20.4
2029	24.0	22.2	23.3	20.3
2030	23.9	22.2	23.2	20.3

A.5 GHG Forecast Approach

The estimates were 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) (6) and the NEB's production projections from the report *Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2014* (EF 2016) (7). ECCC used the details of the projected GHG emissions and productions that were specific to the *with current measures* reference scenario (6). 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* (10), 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 (11). 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 (12). As these plans get defined and take effect, they will be incorporated in future emissions projections and future upstream GHG assessments. As outlined in the proposed methodology published March 19, 2016 (2), ECCC will be examining other data sets, such as data reported for regulatory purposes, and incorporating them into the final assessment, as appropriate.

For the purposes of this assessment, ECCC developed emission factors representing the relative upstream emissions contributions per unit volume of product category. Each category of product that may enter the pipeline has an associated specific emission factor that depends on the emissions generated during its extraction, upgrading, and refining, when this occurs. In order to develop emission factors, ECCC divided projected GHG emissions as published in the *Canada's Second Biennial Report on Climate Change* (6), by the respective production projection obtained from the NEB (7). The resulting emission factors are presented in Table 3.

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

Year	Refined Products	Conv. Light	Conv. Heavy	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2020	116.7	68.7	58.6	82.4	75.4	44.2	103.7
2021	115.6	69.0	58.2	82.4	75.8	44.4	104.1
2022	112.9	69.2	57.7	82.4	76.1	44.6	104.5
2023	108.8	69.3	57.2	82.4	76.1	44.7	104.6
2024	109.0	69.4	56.7	82.4	76.1	44.7	104.6
2025	109.3	69.5	56.4	82.4	76.1	44.7	104.9
2026	109.5	69.6	56.2	82.4	75.9	44.7	104.8
2027	109.6	69.7	55.9	82.5	75.8	44.7	104.7
2028	109.5	69.7	55.6	82.6	75.5	44.7	104.5
2029	102.6	69.8	55.4	82.7	75.4	44.7	104.4
2030	102.4	69.8	55.1	82.8	75.3	44.7	104.4

The throughput for each product category was determined by taking into account the project's expected throughput (890,000 bbl/d) and expected product mix (see A.3 above).

Each product category's share of the total throughput was adjusted, where applicable, to exclude the diluent portion associated with transporting that category of product. The total diluent volume moving through the pipeline also has upstream emissions associated with its production. According to the NEB (7), most of the diluent is expected to be imported from the U.S. Upstream emissions were only estimated for the portion of the diluent that is expected to be produced in Canada. The majority of diluent produced in Canada results from field production followed by gas processing operations. The field production operations are expected to be similar to those of conventional light crude oil production. The emission factors for conventional light crude oil were therefore used for the diluent portion that is produced in Canada.

The emission factors in Table 3 were multiplied by the throughput of each product category transported in the expanded pipeline adjusted for diluent. For a given scenario, the sum of the calculated emissions for each product category is the estimated upstream emissions, as presented in Table 2. Emissions estimates were developed for each year, starting at the expected start date of the project (2020) and up to the end of the forecast period (2030).

Part B. Impacts on Canadian and Global Upstream GHG Emissions

B.1 Introduction

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

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

Part B discusses the conditions under which the production of the oil volumes associated with a fully-utilized TMX project could be incremental. Part B focuses on the additional volumes (+590,000 bbl/d) of crude oil and refined products that could be transported on a fully-utilized TMX project rather than the emissions associated with all of the oil and refined products (890,000 bbl/d) transported on the pipeline. This Part assumes that if the project did not proceed, Kinder Morgan would continue to operate the existing pipeline at its current rate in the future (~300,000 bbl/d).

Part B is divided into four sections. The *Crude Oil Production Outlook* section discusses projections for future oil production in Canada and globally as well as upstream GHG emissions growth in Canada, current and future markets for Canadian oil production growth, and Canada's climate commitments in relation to oil sands production growth. The *Crude Oil Pipeline and Crude-by-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 and Pipeline Capacity Additions* 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 assessment. Several limitations associated with the overall assessment in Part B are provided in Annex B.

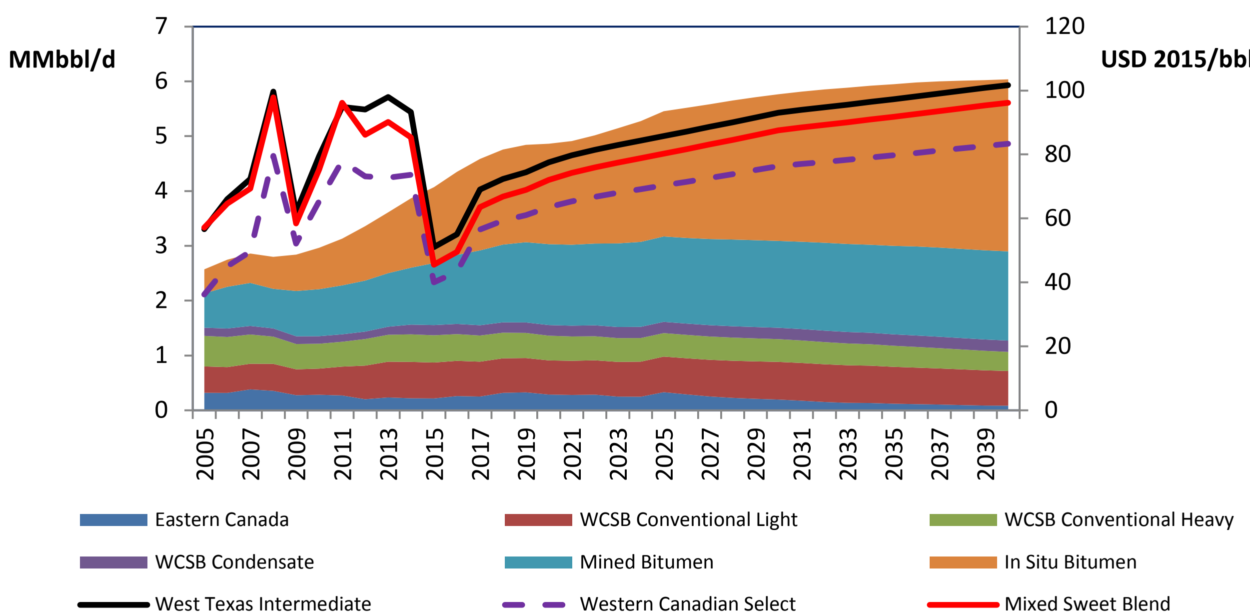
B.2 Crude Oil Production Outlook

This section discusses the NEB's projections of Canadian oil production growth, ECCC's GHG emissions projections, and the outlook for crude oil globally. It then discusses potential markets for Canadian crude oil, oil market uncertainties, and the constrained pipeline case from the *EF 2016* report (7). The section concludes with a discussion of Canada's GHG emission reduction commitments and the potential implications for Canadian oil sands production growth.

B.2.1 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 Case* in the *EF 2016* report, oil production in Canada is expected to increase 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 under the *Reference Case* is expected from mining operations, with only limited growth in upgraded bitumen over the forecast period. Projected growth in oil sands production under the *Reference Case* represents a doubling by 2040 from 2014 levels (See Figure 1) (13). Most production forecasts, including the NEB's *Reference*, *High Price*, and *Low Price Cases*, assume pipeline capacity will be built as required.

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



Source: NEB (7)

Since most Canadian oil production growth is expected to be comprised of *in situ* bitumen, Canadian crude oil production growth transported on any additional pipeline or rail transportation capacity in the future will be largely comprised of diluted bitumen (dilbit) blends from Western Canada[vii]. This conclusion informs the discussion throughout Part B.

In the *EF 2016 Reference Case*, the price of West Texas Intermediate (WTI) – a North American crude oil benchmark – averages USD $51/bbl ($2014) 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, while Canadian Mixed Sweet Blend (MSW), the benchmark light crude oil from Western Canada, is priced USD $5.50/bbl lower than WTI.

EF 2016 also examines a *Low Price Case* and a *High Price Case* of oil prices and presents the impact on Canadian crude oil production. In the *Low Price Case*, 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 Case*, 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 Case*, oil sands production grows slowly after projects already under construction are completed, and reaches 3.8 MMbbl/d in 2040, approximately 21% lower than the *Reference Case*. In the *High Price Case*, oil sands production reaches 5.3 MMbbl/d in 2040, approximately 6% higher than the *Reference Case* (7).

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 or deferrals if oil prices stay low (7). Forecasts from the Canadian Association of Petroleum Producers (CAPP) and the Alberta Energy Regulator (AER) also show that most supply growth to the end of the decade is largely '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 Table in Annex C). After including the necessary diluent for transporting diluted bitumen, additional pipeline-grade product available for transport by 2020 increases to nearly 720,000 bbl/d[viii].

B.2.1.1 Canada's GHG Emissions Projections

ECCC projects that Canada's total annual GHG emissions will increase 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* (6). 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* (10), will

[vii] In Part A, diluted bitumen is included in the *SAGD Heavy*, *Mined Bitumen*, and *CSS Heavy* categories

[viii] 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.

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 (11). 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 (12). 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 (6).

B.2.2 Global Crude Oil Outlook

Oil demand growth is expected to be driven in the future by emerging economies, particularly China, the Middle East, and India (14). In its *New Policies Scenario*, the International Energy Agency (IEA) projects world crude oil demand to grow from 90.6 MMbbl/d in 2014 to 95.9 MMbbl/d in 2020, and up to 103.5 MMbbl/d by 2040. Of the 0.9 MMbbl/d of demand growth expected annually through to 2020, the IEA estimates that 0.35 MMbbl/d will be from China, 0.2 MMbbl/d from the Middle East, and 0.18 MMbbl/d from India, with the remainder from other regions. By 2040, the IEA's *New Policies Scenario* estimates that Chinese crude oil demand will reach 15.3 MMbbl/d, up from 10.5 MMbbl/d in 2014. The IEA expects oil demand growth to slow overall after 2020. However, Brazil and India are notable exceptions as the IEA expects demand growth in these markets to satisfy the increasing energy and mobility needs of growing middle classes. For example, India's demand for oil is expected to surpass the European Union in the 2030s, and to reach 10 MMbbl/d in 2040, approximately 2.5 times higher than the current level of demand (14).

Countries from the Organization for Economic Cooperation and Development (OECD) are expected to continue to experience structural declines in crude oil demand, with the IEA estimating an average annual decline of 1.2%. Respectively, Japanese, European, and U.S. demand for oil is forecast to decline approximately 44%, 35%, and 27% from 2014 levels by 2040.

In the IEA's *450 Scenario*, in which the world has a 50% chance of limiting the long-term increase in average global temperatures to no more than 2°C, global oil demand peaks by 2020 at 93.7 MMbbl/d and declines 18% from 2014 levels to 74.1 MMbbl/d in 2040. However, the IEA notes that in both the *New Policies* and the *450 Scenario* a substantial amount of new oil resources are required to be produced since a large amount of investment is expected to compensate for declining output at existing oil and gas fields (14).

B.2.3 Current and Potential Markets for Canadian Oil Sands Production Growth

B.2.3.1 Current Markets

Canadian refineries source approximately two thirds of their crude oil feedstock from domestic production (15). In 2014, Canadian refineries processed around 1 MMbbl/d of Western Canadian crude oil with the largest refinery markets in Canada located in Alberta and Ontario (15). CAPP reports that Western Canadian refineries processed approximately 0.6 MMbbl/d of Canadian crude oil in 2014. Refineries in Ontario have access to Western Canadian crude oil through the Enbridge Mainline system, and processed nearly 0.36 MMbbl/d of Canadian crude oil in 2014.

Eastern Canadian refineries tend to consume more foreign-sourced crude oil. However, the reversal of Enbridge's Line 9B has increased pipeline capacity for Western Canada crude oil by 300,000 bbl/d to refineries located in Quebec (15). In 2014, refineries on the East Coast of Canada processed approximately 34,000 bbl/d of crude oil produced in Eastern Canada (15).

In 2014, 97% of Canadian crude oil exports went to the U.S. The U.S. is divided into five petroleum markets termed Petroleum Administration for Defense Districts (PADD): PADD 1 (East Coast); PADD 2 (Midwest); PADD 3 (Gulf Coast); PADD 4 (Rocky Mountain), and; PADD 5 (West Coast).

PADD 2 is the second largest refining market in the U.S. and the largest market for Canadian crude oil. In 2014, refineries in PADD 2 processed 3.5 MMbbl/d of oil which represented 23% of U.S. crude oil consumption (see Table 4) (16) (17). In addition, PADD 2 refineries use large volumes of heavy oil as inputs. In 2014, refineries in PADD 2 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 Canadian heavy oil. Exports to PADD 2 accounted for 71% of all Canadian heavy oil exports in that year[ix].

Table 4: U.S. 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 2 (Midwest)	3.52	23%	1.29	31%	1.13	71%
PADD 3 (Gulf Coast)	8.25	53%	2.16	52%	0.13	8%
PADD 4 (Rocky Mountains)	0.25	2%	0.17	4%	0.17	10%
PADD 5 (West Coast)	2.4	15%	0.37	9%	0.07	4%
U.S. Total	**15.51**		**4.14**		**1.59**	

Source: CAPP forecast based on data from the U.S. Energy Information Administration (15) and the NEB (7).

[ix] 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.

Both the NEB and CAPP have noted that refineries in PADD 2 have little scope to process more heavy oil. Expansion of heavy oil processing capacity at PADD 2 refineries is likely to be inhibited by the growth in light tight oil production from the U.S., which has reduced the expected profitability of further refinery conversion projects (9). As such, growth in Canadian oil sands production is more likely to be transported to other markets than PADD 2.

B.2.3.2 Potential Markets for Canadian Oil Sands Growth

If constructed, the TMX project would provide Canadian oil producers with access to potential refinery markets in the Pacific basin, including China and Western U.S. markets. Given the expected growth in heavy oil production in Canada, the potential for heavy oil processing in the Pacific market is discussed below. Overall, Pacific refinery markets represent a source of potential demand for Canadian crude oil, including diluted bitumen from the oil sands given the expected demand growth in the region and the existence of 19.4 MMbbl/d of nameplate refinery capacity (18)[x].

A key determinant of refinery demand for heavy oil in Pacific markets is the availability, or potential for development, of coking capacity at refineries. This process enables a refinery to process the less valuable heavy portion of a barrel of crude oil into higher value products (19). Future investment decisions about refinery expansions will affect the types of crude oil that will be sold in Pacific markets and this will be informed primarily by the price difference between light and heavy oil in the region.

Reports from Hackett et al. (20) and Muse Stancil (9) indicate that the most likely markets with existing ability to process Canadian heavy oil in the Asia Pacific market are California, China, Japan, and Korea. There may also be demand for Canadian crude oil in India and Southeast Asia, though transportation costs to these markets could make them less profitable for Canadian producers (9). Estimates from Muse Stancil and RWDI produced for the project proponent indicate that the expanded Trans Mountain pipeline would carry a substantial amount of diluted bitumen (9). If the expanded Trans Mountain pipeline carries mostly diluted bitumen, refineries in Asia Pacific would either expand heavy oil processing capacity or use more Canadian heavy crude oil and substitute away from other sources of heavy oil.

While the Pacific market offers opportunities for Canadian crude oil, there are potential competitive challenges. Currently, light and medium Middle Eastern crude oil are the primary sources of imports in the Pacific market (9). Recent capacity expansions at refineries in China have been the result of joint ventures between Chinese state oil companies and foreign investors, particularly Saudi Arabia and Russia. According to the U.S. Energy Information Administration (U.S. EIA), Saudi Arabia and Russia have sought these arrangements in an effort to secure market share for their own production (20) (21) (22). However, analysis from Wood Mackenzie notes that crude oil suppliers from West Africa and Iraq have made inroads in supplying refineries in Asia, which has increased price competition in the region (23) (24). Finally, the IEA has noted that, in the medium term, the Pacific market may have excess refining capacity, which could lead to shutdowns or lower utilization (14) (25). Despite competition from other

[x] This figure represents crude distillation capacity in refineries from PADD 5, China, Taiwan, Japan and Korea.

suppliers, the Muse Stancil analysis undertaken for the proponent suggests that the Pacific market could absorb crude oil carried on TMX (9). Specific markets in the Pacific basin are discussed below.

B.2.3.2.1 China

China has the greatest amount of refining capacity in Northeast Asia at approximately 8.3 MMbbl/d, and significant capacity to process heavy oil (18) (26)[xi]. The Chinese refinery sector is currently expanding. The U.S. EIA reports that 1.9 MMbbl/d of refining capacity is currently under construction and expected to come into service between 2015 and 2020, some of which includes heavy oil refining capacity (21) (26). However, approximately 30% of the 1.9 MMbbl/d of additional capacity is being built under joint venture agreements, mainly with Saudi Aramco and Russia's Rosneft (21) (27) (28). Joint ventures do not necessarily exclude those refineries from purchasing crude oil from other sources, such as Canada, but could limit opportunities at these refineries (9) (24)[xii]**.** In addition, China has arrangements to provide loans to Venezuela in exchange for crude oil (29).

B.2.3.2.2 Japan

Historically, Japan has been a market for light and medium crude oil. In 2014, Japanese refineries imported 83% of their crude oil from the Middle East, but have indicated interest in further diversifying their suppliers (9). Japan is a large refining market with a total refining capacity of 3.9 MMbbl/d. Muse Stancil estimates that approximately 9% of this capacity is well suited to process heavy crude oil and as a result, there is likely limited demand for heavy crude in Japan. As such, it may be a more likely market for Canadian light and medium oil that could also be shipped on TMX (9).

B.2.3.2.3 South Korea

South Korea has nearly 3 MMbbl/d of refinery capacity that is largely configured to process light and medium crude oil. South Korean refineries are not well equipped to process large volumes of heavy oil such as Canadian diluted bitumen (9) (18). In 2013, several South Korean refineries added up to 0.3 MMbbl/d of heavy oil processing capacity (20). However, South Korean refiners have also expressed interest in processing more condensate and light crude oil from the U.S. and Iran, and have made investments accordingly (30). Given the current configuration of Korean refineries towards light and medium crude oil, South Korea may not be a large market for heavy oil exports from Canada. However, like Japan, South Korea could be a potential market for Canadian light crude oil that may also be shipped on TMX (30).

B.2.3.2.4 PADD 5

PADD 5 (West Coast) is the third largest refining market in the U.S. with most of the refining capacity concentrated in Washington and California[xiii]. Refineries in PADD 5 processed 2.4 MMbbl/d of crude oil in 2014, which represented 15% of total US crude oil consumption. Some California refineries are equipped to process heavy oil due to the large volumes of heavy oil historically produced in the state

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[xi] China had approximately 1.3 MMbbl/d of coking capacity in 2010 (26).

[xii] For instance, the Motiva refineries in the U.S. which were owned as a joint venture between Shell and Saudi Aramco frequently purchased non-Saudi crude oils as feedstock. Shell and Saudi Aramco recently decided to split up their assets (9).

[xiii] British Petroleum's Cherry Point and Shell's Anacortes refineries in Washington State have coking capacity capable of processing 0.05 MMbbl/d oil sands crudes if they are part of a higher quality crude mix (20). However, Washington refineries already purchase Canadian heavy oil off the existing Trans Mountain system, so these refineries may not be large sources of incremental demand.

(20) (31). Despite the potential for refineries in California to process Canadian heavy oil, state climate policies, such as its low carbon fuel standard, create uncertainties about the viability of importing Canadian bitumen over the long term.

B.2.3.2.5 PADD 3

PADD 3 includes refineries in the U.S. Gulf Coast and is one of the largest refining markets in the world. In 2014, refineries in PADD 3 processed 8.3 MMbbl/d of crude oil (15) (32). PADD 3 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 3 refineries sourced only 2%, or 0.2 MMbbl/d, of their crude oil inputs from Canada. PADD 3 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 3, supplying 1.4 MMbbl/d (18%) of total crude consumed in 2014 (7) (15). While PADD 3 is not a destination market for crude oil and products that would be transported on the TMX project, it is a large potential market for Canadian crude oil in North America and is discussed below as a likely market in the absence of future pipeline growth.

B.2.4 Oil Market Uncertainties

B.2.4.1 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, and averaged USD $35.08 in the first four months of 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 (April 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 (33). 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 (34).

B.2.4.2 Pipeline Constraints

Increasing production from U.S. light tight oil and from Canada's oil sands in recent years caused pipeline bottlenecks in North America. This has had 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 (7). 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 Western Canadian Sedimentary Basin (WCSB) are at, or nearing, their effective capacities as evidenced by the many pipelines under apportionment[xiv]. Current pipeline projects, including the TMX project, which have been proposed to and/or approved by the NEB, have a cumulative capacity of over 3.4 MMbbl/d (15).

B.2.4.2.1 NEB Constrained Oil Pipeline Capacity Case (*Constrained Case*)

As part of the *EF 2016 report*, 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 built; however, Enbridge's proposed Line 3 replacement project is completed. As such, the *Constrained Case* assumes that the Enbridge Mainline expansions and crude-by-rail are the only options available to transport Canadian crude oil production growth. Further, the NEB analysis, like this assessment, assumes that the primary growth market for Canadian exports of heavy crude from the oil sands, in the absence of additional pipeline capacity, would be the U.S. Gulf Coast (see section B.2.3.2).

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 Case* 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*.

B.2.5 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^{o}C and pursue efforts to limit the increase to 1.5^{o}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^{o}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

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[xiv] In its fourth quarter 2015 Management's Discussion and Analysis (56), 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 pipeline transportation space exceeds the available shipping capacity for that type of oil on a pipeline. The space on a pipeline under apportionment is rationed between bidding parties, typically on a pro-rata basis. 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.

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 (35). 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 (36).

Other projections show that oil sands production could continue to expand from current levels while still limiting warming to 2°C: for example, the IEA's World Energy Outlook's *450 Scenario* (14). 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 (37).

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 significant innovation in currently unknown technologies, and highlights the importance of low carbon extraction techniques for the oil sands and carbon capture and storage for Canada's decarbonisation aspirations (38).

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 provincially, nationally, and 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 assessment 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.

B.3 Crude Oil Pipeline and Crude-by-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 on similar distances, rail has been generally recognized as being more emissions intensive than transporting oil by pipeline. The emission intensity of a Class 1 freight railway is approximately 15.8 kg CO_2 eq/1000 tonne kilometres (39). In comparison, ECCC estimates that the emission intensity of an oil pipeline traversing Alberta and British Columbia is 6.0 kg CO_2 eq/1000 tonne kilometres, including emissions associated with grid electricity used to power pumping stations along the pipeline. As such, in the absence of the project, if crude is transported via rail, this transportation option would result in higher direct transportation emissions in Canada. It is important to note that several factors influence the emission intensity of specific rail and crude oil pipelines routes. Therefore, depending on the specific project in question, the difference in emission intensity between the two modes of crude oil transport will vary. Due to differences in methodology, ECCC's estimated emission intensity for pipeline operations may not be comparable to the estimates of operational emissions that the proponent has made as a part of their submission to the NEB.

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.

B.3.1 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 105,000 bbl/d in 2015. Crude-by-rail export volumes peaked at 173,000 bbl/d in September 2015, and declined to under 130,000 bbl/d in early 2016 (40). Furthermore, the NEB reports that crude-by-rail shipments in Canada (i.e., exports and domestic delivery) reached their highest historical level of 241,000 bbl/d in 2014 (41).

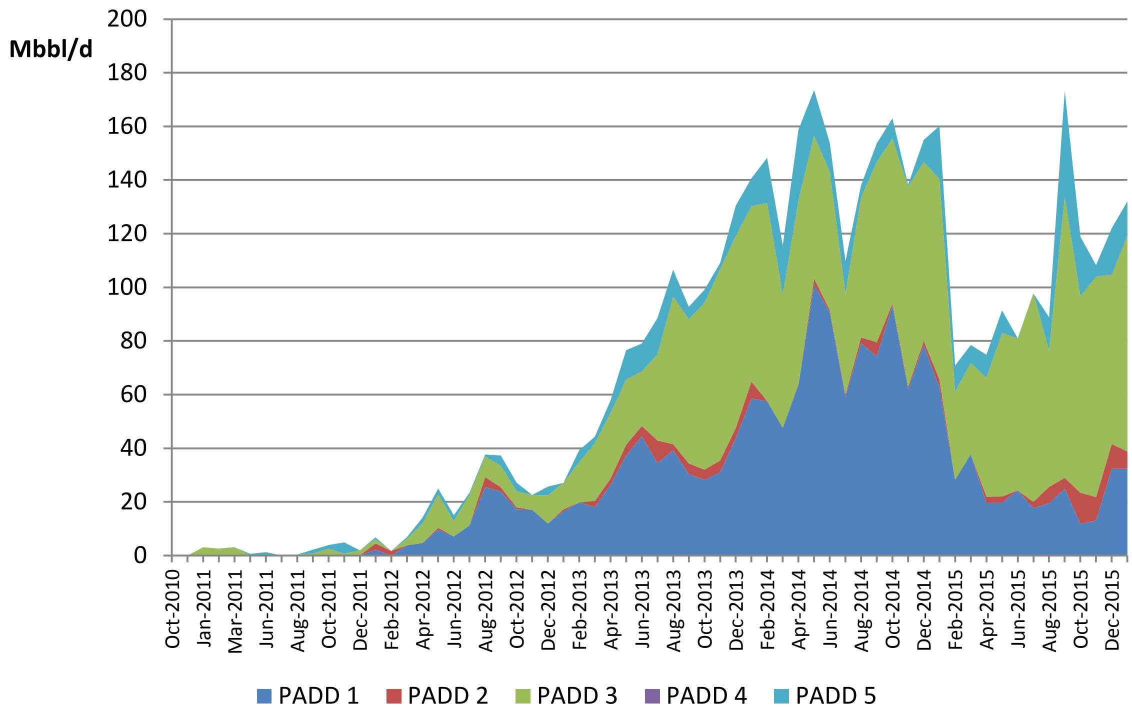
While crude-by-rail exports from Canada were initially spread fairly evenly between PADDs I and III, the destination for exports shifted towards PADD 3 in 2015. These figures do not include crude-by-rail volumes transported within Canada (see Figure 2).

Several Canadian refineries and ports have installed or expanded crude-by-rail offloading capacity including Suncor Energy Product Partnerships' Montreal refinery (35,000 bbl/d), Valero's Jean-Gaulin refinery in Lévis, QC (60,000 bbl/d), Irving's Saint John refinery (200,000 bbl/d), Chevron's Burnaby refinery (7,000 bbl/d), and the Sorel-Tracy terminal in Quebec (33,000 bbl/d)[xv].

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 2 (Midwest) increased from an average of 90,000 bbl/d in 2011 to 615,000 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.

[xv] Figures compiled from news sources and discussions with the NEB.

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



Source: U.S. Energy Information Administration, Crude Oil Movements of Crude Oil by Rail (40)

B.3.2 North American Crude-by-Rail Loading & Offloading Infrastructure

There have been questions as to 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.). Infrastructure 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 development of rail transport infrastructure and services from a coal basin as a precedent for the possibility of rapid railway expansion (42). Furthermore, the expansion of crude-by-rail capacity in the U.S. is illustrative of the rate and level of potential rail infrastructure development when market factors create the incentive for this investment.

Crude-by-rail loading capacity from the WCSB has expanded significantly in the past five years. While traditionally it was employed 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 nameplate loading capacity in Alberta and Saskatchewan is 1.1 MMbbl/d (43)[xvi]. In the U.S., crude-by-rail offloading capacity is concentrated in PADD I and PADD 3. Recent estimates from RBN Energy indicate that nearly 1.7 MMbbl/d of rail offloading capacity currently exists in PADD 3 (44). The KXL FSEIS estimated that rail offloading capacity in PADD I was nearly 1 MMbbl/d in

[xvi] The Department of State Final Supplemental Environmental Impact Statement (KXL FSEIS) Market Analysis notes data from the North Dakota Industrial Commission (57) that indicates effective rail capacity at around 80% of nameplate capacity.

2013 (42). Estimates from the U.S. Dept. of State indicate that PADD 2 had around 50% of total U.S. crude loading capacity in 2013, at 1.2 MMbbl/d, concentrated in the Bakken fields of North Dakota (42).

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. For diluted bitumen, 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. Decreasing the amount of diluent in the oil sands blend reduces the costs per barrel of bitumen transported and decreases any financial losses from the difference in diluent value between the origin and destination markets (45). Alternative bitumen blends hauled on rail are railbit (15-20% diluent) or rawbit (0-2% diluent). Transporting rawbit requires special tanker cars and loading/offloading facilities, which are not widely used at this time (45).

B.3.3 Relative Costs of Pipelines and Rail

This assessment presents scenarios (see below in B.4) that include a baseline scenario in which crude-by-rail is the primary transportation option available to move oil sands production growth to market, and two additional scenarios in which TMX and other pipelines are built. Under the baseline scenario, it is assumed that the primary market for Canadian production growth would be PADD 3 (Gulf Coast), in the absence of further pipeline capacity being built from Western Canada. This assumption is supported by the considerations noted above that PADD 3 is a large refining market, with significant heavy oil refining capacity and scope to process greater volumes of Canadian crude oil, and with a large amount of rail offloading capacity. For scenarios in which TMX is built, it is assumed that some portion of Canadian oil sands production growth would be exported to Asia on a combination of pipeline and tanker.

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 some of these projects may not be built in the absence of new pipelines.

The difference in the transportation costs between using crude-by-rail to transport oil sands crude to PADD 3 and using the proposed TMX pipeline to British Columbia illustrates the costs producers would face from a common starting point, Edmonton, AB. Crude-by-rail rates taken from the KXL FSEIS and adapted by ECCC to reflect shipment from Edmonton indicate that shipping diluted bitumen from Northern Alberta to Port Arthur, Texas would cost around USD $18.00/bbl and the rail rates to Los Angeles, California would be around USD $16.00/bbl assuming volumes are moved on a 100 tanker car unit train (see Table 5)[xvii]. By comparison, transporting diluted bitumen on TMX from Alberta to the Port

[xvii] Rail rates assume pipeline transportation to Edmonton and rail to final destination.

of Vancouver, and then shipping it by Aframax tanker to key Pacific basin refining centres is expected to cost between USD $6.50/bbl and $10.50/bbl depending on the final destination and whether pipeline tariffs are based on committed rates (i.e., under long-term contract) or uncommitted rates[xviii]. It is expected that more than 700,000 bbl/d of total planned TMX capacity of 890,000 bbl/d would be under committed contracts with shippers, leaving the remaining capacity for uncommitted shippers (46).

The estimated pipeline tolls for TMX are based on the proponent's NEB filings while the tanker rates from Westridge, British Columbia to Asia and California were adapted from estimates provided by Muse Stancil as part of the proponent's submission for the TMX project (47)[xix].

The analysis below takes a conservative approach, reflecting a large potential spread in transportation costs between scenarios. That is, it uses an average crude-by-rail cost to Port Arthur, Texas of USD $18.00/bbl and an average transportation cost of USD $9.00/bbl to Asia using a committed pipeline toll and estimates of rates on an Aframax tanker, which translates into a difference in transportation costs between these options of USD $9.00/bbl of diluted bitumen.

Table 5: Diluted Bitumen Transportation Costs from Edmonton (Alberta) to Major Markets via Various Modes of Transportation

Point of Receipt	Shipping Basis	Transport Cost (USD/bbl)
Port Arthur, Texas	Rail	$18.00
Los Angeles, California	Rail	$16.00
Quanzhou, Southern China	TMX Committed/Tanker	$9.00
	TMX Uncommitted/Tanker	$10.50
Tsingtao, Northern China	TMX Committed/Tanker	$9.00
	TMX Uncommitted/Tanker	$10.50
Yosu, South Korea	TMX Committed/Tanker	$8.50
	TMX Uncommitted/Tanker	$10.00
Chiba, Japan	TMX Committed/Tanker	$8.50
	TMX Uncommitted/Tanker	$10.00
Los Angeles, California	TMX Committed/Tanker	$6.50
	TMX Uncommitted/Tanker	$8.00

Source: ECCC, U.S. Department of State (42), Muse Stancil (9), Trans Mountain Pipeline ULC (48)

This transportation cost difference between scenarios is likely a high-end estimate since:

1) As noted above, producers could send bitumen blends with low or no diluent via rail that would reduce crude-by-rail transportation costs per barrel of bitumen transported. In a scenario in

[xviii] Muse Stancil (9) assumes that all crude oil shipped on TMX is transported from the Westridge to foreign markets by Aframax tankers with a capacity of 80,000 deadweight tonnes, or 541,600 bbl of Cold Lake grade bitumen.
[xix] The tolls used in this estimate are representative, and could fluctuate with changes in project capital costs. Specifically, the TMX project is expected to cost $6.8 billion, which is higher than the costs originally reported in the project's application to the NEB of $5.4 billion.

which rail was the only transportation option, producers may have further incentive to invest in facilities to enable further transportation of railbit or rawbit.

2) The cost difference implicitly assumes that the difference in transportation costs for Canadian producers remains static over the long term, which is unlikely. For example, companies may choose to use some combination of rail, pipeline and barge transportation to move barrels from Western Canada if no additional pipeline capacity were built which could further lower transportation costs under a no-pipeline scenario.
3) The $9.00/bbl cost difference does not incorporate tax or royalty considerations, which would decrease the relative difference in transportation costs in after-tax terms[xx].

Even with a cost difference, there are some advantages to rail including greater flexibility in destinations and shorter transport times between the same destinations. Other benefits are discussed in CAPP's 2015 crude oil forecast (15).

In addition, crude oil price differences between the Asia Pacific and PADD 3 markets could increase revenues for producers shipping on TMX, enhancing returns beyond the transportation costs noted above. These price differences are not considered in this assessment given the level of estimation uncertainty.

B.4 Incremental Emissions and Pipeline Capacity Additions

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 TMX project were built than if it were not built. It considers two pipeline scenarios: 1) no additional pipeline capacity from 2015 capacity levels is built other than the TMX project, and 2) other additional pipeline capacity as well as the TMX project is built such that shipping large volumes of crude-by-rail is no longer needed[xxi]. 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.

B.4.1 Baseline: No new pipeline capacity built from WCSB

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 bitumen capacity, equivalent to 720,000 bbl/d of pipeline-grade oil) will be transported via rail. If future projects were expected to be sufficiently profitable when transporting oil-by-rail, they would proceed in the baseline.

B.4.2 Scenario 1: TMX is the only new pipeline capacity built

As discussed previously, it is likely that production growth from oil sands projects already under construction will continue as planned. In a scenario in which the TMX project were built, but no other pipeline capacity from the WCSB was built, some portion of this production growth and/or some portion of current crude export volumes on rail would likely shift to the additional pipeline capacity (590,000

[xx] 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.

[xxi] 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.

bbl/d) available on the TMX project. Under these circumstances, none of the barrels transported on the TMX 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 project was built. In this scenario, oil transportation by rail would be required to get oil to markets both before and after the completion of the TMX project since the TMX project is expected to add 590,000 bbl/d of capacity and 'locked in' production growth and volumes currently moving on rail are greater than this amount.

B.4.3 Scenario 2: TMX and other pipeline capacity is built

If the TMX project and other pipelines are built such that large-scale rail shipments of crude oil were no longer needed, then the additional pipeline capacity (the TMX 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 TMX project, or any specific pipeline project, would be difficult.

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

B.4.3.1 Oil Sands Supply Costs and Additional Costs from Crude-by-Rail

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 (usually 10-15%) (7). 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. For the purposes of this assessment, supply cost estimates are benchmarked to Canadian light oil at Edmonton, Alberta and presented in USD terms.

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 (49)[xxii,xxiii]. *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[xxiv]. 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.

To assess the impacts of transportation options on oil sands supply costs, ECCC developed an oil sands supply curve. The supply curve uses ECCC's in-house oil sands project model and publicly available information on over 150 *in situ* oil sands project phases that have been announced, are awaiting approval or have been approved by the regulator (referred to as *potential in situ* oil sands capacity), but

[xxii] IHS (2015) *Oil Sands Cost and Competitiveness*
[xxiii] Wood Mackenzie (2016): GEM Tool
[xxiv] Integrated mining projects are not discussed in this piece because few new integrated mining projects are planned at this time.

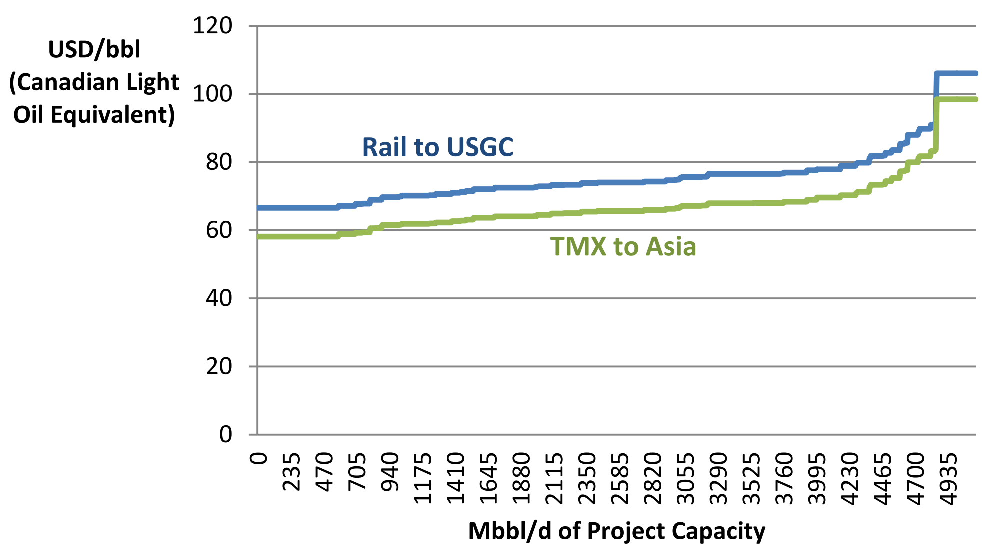
are not under construction or currently operating. These projects are expected to be sources of supply growth in the oil sands post-2020.

The supply curve indicates that a substantial amount of potential *in situ* oil sands project capacity has supply costs that range between USD $50 and $70/bbl assuming pipeline transportation to Asia via TMX (see Figure 3). Based on the incremental cost estimates for transporting crude oil by rail above (+USD $9.00/bbl), it is expected that the supply cost range for a large amount of planned projects post-2020 would be between around USD $60 and 80/bbl in the baseline scenario where producers used rail to PADD 3 rather than shipping diluted bitumen via TMX[xxv].

B.4.3.2 Comparing a Supply Curve to a Production Forecast

The supply curve developed by ECCC represents a rank ordering of potential oil sands projects that could be developed in the future. While the ECCC oil sands supply curve indicates potential *in situ* project capacity of up to 5 MMbbl/d, this does not mean that all of these projects will come online.

Figure 3 - Oil Sands Supply Curve for Unsanctioned *In Situ* Projects, Canadian Light Oil Equivalent @ Edmonton (USD/bbl)



Source: ECCC Oil Sands Supply Model

The feasibility of developing the full 5 MMbbl/d of potential oil sands capacity is limited by the considerable amount of capital and labour required to construct and operate the facilities. Historically, increased development in the oil sands has led to capital and operating cost inflation that has driven up supply costs and dampened the returns on future investment. As well, the attractiveness of individual projects depends on world oil demand, crude oil prices, and the prospects for competing alternative investments. Many of the projects included in ECCC's oil sands supply curve will likely remain

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[xxv] Key assumptions (exchange rates, price differentials) that drive the oil sands model were taken from the NEB (7). Other assumptions include a long run steam-to-oil ratio (SOR) of 3 for projects, average variable operating costs of $12/bbl of bitumen, sustaining capital costs of $8/bbl, a required rate of return of 12% (nominal), cost and commodity price inflation of 2% per year, no cogeneration at facilities, and Alberta's climate policy at $30/tonne CO_2 eq (real) on 24% of emissions with carbon costs escalated at 2% per year.

undeveloped because other investment opportunities in the crude oil sector have become available over the past five years which could offer better returns on capital over a shorter timeframe.

Remodeling the supply curve to reflect the difference in transportation costs between rail and TMX to Asia is done to illustrate the change in costs, but should not be interpreted as the TMX project lowering the supply costs of all potential *in situ* projects in the future. In effect, this transportation cost impact may only be realized by a few oil sands projects. Furthermore, the shift in the supply curve as a result of the incremental transportation costs is relatively small in comparison to the impact of oil price movements in general.

Adding pipeline capacity could enable greater production if the reduction in transportation cost associated with pipeline transport is sufficient to make potential projects financially viable that would not have otherwise been without the pipeline capacity. However, the price of crude oil plays the primary role in determining the attractiveness of an investment in oil sands production capacity, and thus its expected value influences the degree to which pipelines could cause incremental production and, therefore, upstream emissions.

B.4.3.2.1 Low Prices

If long-term Canadian light oil prices were below USD $60/bbl in real terms and rail were the only transportation option available to oil producers, there is unlikely to be substantial oil sands production growth post-2020 without a significant decrease in production costs from current levels. An example of this low growth is the *EF 2016 Low Price Case* discussed above that has WTI 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 Canadian light oil prices were below USD $60/bbl, building pipeline capacity would not be expected to result in additional oil sands development.

B.4.3.2.2 Mid-Range Prices

If long-term Canadian light 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.

All else being equal, supply cost estimates indicate that a considerable amount of potential *in situ* oil sands production capacity could become profitable (~4.3 MMbbl/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 TMX and other pipeline projects are completed, is considered to result in incremental upstream GHG emissions. Therefore, if long-term oil prices were in this range, some production growth could be incremental. To the degree to which incremental rail costs are lower than the USD $9.00/bbl estimated transportation difference, the amount of incremental production and associated incremental upstream GHG emissions, if any, would be lower due to more attractive project economics as well as higher revenues and investment.

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

B.4.3.2.3 High Prices

If longer term Canadian light 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 marginal given the availability of capital in global financial markets which would reduce the reliance of companies on internally generated cash flow to support capital investment. As such, less production is expected to be incremental at light oil prices above USD $80/bbl than when prices are in the USD $60-$80/bbl range.

B.4.3.3 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 6).

Table 6: Potential Incremental Oil Sands Production in Canada

	Price		
	<$60	**$60-80**	**>$80**
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 MMbbl/d	~4.3 MMbbl/d	~5.0 MMbbl/d

Source: ECCC

B.4.3.4 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 (50). 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 (51).

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 around the world. 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, often referred to as well-to-tank emissions (WTT)[xxvi].

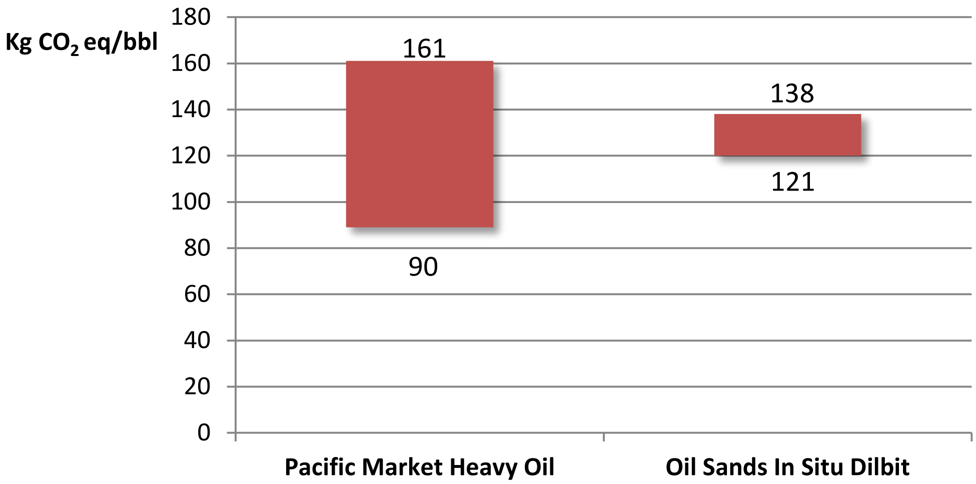
The Pacific market processes numerous types of light to heavy crudes, mostly from the Middle East. There is very limited data on emission intensities for different types of international crude oil and this data is often not consistently reported between jurisdictions. In a 2014 report*,* IHS CERA presents estimates of the lifecycle emission intensities for Canadian domestic and international crudes processed in the U.S. (52). Many of the same types of crude oil are also processed in the Pacific market. The methodology used to determine WTT emissions from oil production in this study is not, however, the same as the methodology to determine upstream emissions intensity used in Part A. As such, emissions factors vary, but are used in this instance to ensure comparability between types of crude oil.

IHS CERA notes that the most likely substitutes for Canadian oil sands are comparable types of heavy oil (52). The report indicates that WTT emission intensities for heavy crude oil used in the Pacific market range between 90 and 161 kg CO_2 eq/bbl while the WTT emissions for Canadian *in situ* diluted bitumen range between 121 and 138 kg CO_2 eq/bbl depending on the production process. As can be seen in Figure 4, there is significant overlap in estimated WTT emissions intensities between different types of heavy oil from Canada and in the Pacific market.

Since WTT GHG emissions from Canadian oil sands diluted bitumen are within the same range as comparable types of heavy oil, the impact on global emissions of increased Canadian oil sands diluted bitumen reaching global markets depends on the mix of crude oil being displaced by Canadian diluted bitumen.

[xxvi] 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.

Figure 4 - Well-to-Tank GHG Emission Intensity Ranges by Type of Heavy Crude Oil used in the Pacific



Source: IHS CERA (52). Heavy oil used in the Pacific includes Venezuelan, Brazilian high tan, and California Heavy. Canadian diluted bitumen range reflects SAGD diluted bitumen and CSS diluted bitumen.

B.5 Conclusions

The analysis in Part B provides insight into the conditions under which building the TMX 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 TMX 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 TMX project. Under this scenario, it is likely that the upstream emissions calculated in Part A would occur regardless of whether the TMX project was built or not.
- *If additional pipeline capacity, including TMX, 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 specifically by the TMX project.
    - At long-term Canadian light oil prices lower than USD $60/bbl, most potential 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 long-term Canadian light oil prices of USD $60-80/bbl, many potential projects that would not be profitable if rail were the only transportation option could become profitable with pipeline access. However, the actual amount of incremental production that would come online is uncertain.

    - At long-term Canadian light oil prices of greater than USD $80/bbl, many potential 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 significantly 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. 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[xxvii]. Data from IHS indicate that the WTT emissions from oil sands *in situ* diluted bitumen are within the range of other types of heavy oil currently used in the Pacific market. This indicates that the impact on global emissions of increased Canadian oil sands diluted bitumen reaching global markets depends on the mix of crude oil being displaced by Canadian diluted bitumen.

[xxvii] 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.

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Annex A – Product Mixes

Scenario 1

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2020	18.0	0.8	10.1	37.3	6.4	22.4	4.9
2021	17.5	0.4	5.6	39.8	7.0	24.7	4.9
2022	17.4	0.1	1.8	42.8	7.5	25.4	4.9
2023	17.0	0.1	1.9	42.1	7.4	26.5	4.9
2024	16.9	0.0	0.6	40.1	7.1	30.3	4.9
2025	17.5	0.0	0.6	34.8	6.1	36.0	4.9
2026	15.3	0.0	0.7	38.7	6.8	33.5	4.9
2027	14.2	0.1	0.8	44.2	7.8	28.1	4.9
2028	16.2	0.1	0.7	42.3	7.4	28.4	4.9
2029	13.4	0.0	0.6	44.8	7.9	28.3	4.9
2030	13.1	0.0	0.6	45.3	8.0	28.0	4.9

Scenario 2

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2020	16.8	18.2	8.0	24.2	10.3	17.6	4.9
2021	16.8	17.7	8.0	25.0	10.0	17.6	4.9
2022	16.8	17.1	7.9	25.7	10.0	17.6	4.9
2023	16.8	16.3	7.8	26.6	10.0	17.5	4.9
2024	16.8	15.7	7.8	27.3	9.9	17.5	4.9
2025	16.9	14.1	7.8	28.1	10.8	17.4	4.9
2026	17.0	13.7	7.8	28.7	10.5	17.3	4.9
2027	17.1	13.5	7.8	29.3	10.2	17.3	4.9
2028	17.1	13.2	7.7	29.8	9.9	17.3	4.9
2029	17.1	13.0	7.7	30.3	9.7	17.2	4.9
2030	17.2	12.8	7.7	30.7	9.5	17.2	4.9

Scenario 3

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2020	7.9	18.2	8.0	24.2	10.3	26.4	4.9
2021	7.9	17.7	8.0	25.0	10.0	26.4	4.9
2022	7.9	17.1	7.9	25.7	10.0	26.4	4.9
2023	7.9	16.3	7.8	26.6	10.0	26.4	4.9
2024	7.9	15.7	7.8	27.3	9.9	26.4	4.9
2025	7.9	14.1	7.8	28.1	10.8	26.4	4.9
2026	7.9	13.7	7.8	28.7	10.5	26.4	4.9
2027	7.9	13.5	7.8	29.3	10.2	26.4	4.9
2028	7.9	13.2	7.7	29.8	9.9	26.4	4.9
2029	7.9	13.0	7.7	30.3	9.7	26.4	4.9
2030	7.9	12.8	7.7	30.7	9.5	26.4	4.9

Scenario 4

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2020	34.3	18.2	8.0	24.2	10.3	0.0	4.9
2021	34.3	17.7	8.0	25.0	10.0	0.0	4.9
2022	34.3	17.1	7.9	25.7	10.0	0.0	4.9
2023	34.3	16.3	7.8	26.6	10.0	0.0	4.9
2024	34.3	15.7	7.8	27.3	9.9	0.0	4.9
2025	34.3	14.1	7.8	28.1	10.8	0.0	4.9
2026	34.3	13.7	7.8	28.7	10.5	0.0	4.9
2027	34.3	13.5	7.8	29.3	10.2	0.0	4.9
2028	34.3	13.2	7.7	29.8	9.9	0.0	4.9
2029	34.3	13.0	7.7	30.3	9.7	0.0	4.9
2030	34.3	12.8	7.7	30.7	9.5	0.0	4.9

Annex B – Limitations of the Analysis

There are a number of limitations with the approach taken to discuss whether the construction of the TMX 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.

Annex C – Oil Sands and Heavy Oil Projects Under Construction

Type	Company	Project	Status	Planned bitumen/SCO capacity (bbl/d)	Planned dilbit/SCO capacity (bbl/d)	Estimated Start-up
In Situ	Brion Energy	Mackay River Phase 1	Construction	35,000	50,000	2016
In Situ	Cenovus/ConocoPhillips	Foster Creek Phase G	Construction	30,000	42,900	2016
In Situ	Cenovus/ConocoPhillips	Christina Lake Phase F	Construction	50,000	71,400	2016
In Situ	Japan Canada	Hangingstone Expansion	Construction	20,000	28,600	2016
In Situ	Husky Energy	Edam East & West	Construction	14,500	14,500	2016
In Situ	Husky Energy	Vawn	Construction	14,500	14,500	2016
In Situ	Sunshine Oil Sands	West Ells	Construction	5,000	7,100	2016
Mining	Canadian Natural Resources	Horizon Phase 2/3	Construction	137,000	137,000	2017
Mining	Suncor/Total/Teck	Fort Hills Phase 1	Construction	180,000	225,000	2017
In Situ	Cenovus/ConocoPhillips	Foster Creek Phase H	Construction delayed[xxviii]	30,000	42,900	2018
In Situ	Cenovus/ConocoPhillips	Christina Lake Phase G	Construction delayed	50,000	71,400	2018
In Situ	Harvest Operations Corp	BlackGold Phase 1	Steaming delayed[xxix]	10,000	14,300	2018
Total under construction or expected				**576,000**	**719,600**	

Source: IHS (53); CanOils (54); Company Reports

[xxviii] 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.

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