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

November, 2016

This page intentionally left blank.

Contents

Executive Summary

This document provides an estimate of the upstream greenhouse gas emissions (GHG) associated with the transportation capacity on the Trans Mountain pipeline system, and a discussion of conditions under which they could be considered incremental[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 that could be transported by the expanded Trans Mountain pipeline system if the project is approved. Currently, publicly-available data and established methodologies do not allow for the inclusion of indirect emissions such as those associated with land-use changes and grid electricity or fuels that are produced elsewhere. The projections for GHG emissions and production used for this review were modelled up to the year 2030 and include the estimated future impacts of existing policies and measures as of September 2015. A number of important measures and targets to reduce GHG emissions from the oil and gas sector have been announced since that time, including the Government of Canada's commitment to reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels by 2025 and the Government of Canada's proposed pan-Canadian approach to pricing carbon pollution. While this analysis focuses on policies implemented as of September 2015 and does not reflect the impact of additional federal, provincial or territorial measures announced or under development, it is recognized that future improved practices will mitigate emissions.

The upstream GHG emissions associated with the entire Trans Mountain pipeline system, transporting 890,000 barrels per day, could be between 21 and 26 megatonnes of carbon dioxide equivalent per year. Considering only the 590,000 barrels per day capacity added by the Trans Mountain Expansion Project, the upstream GHG emissions could range from 13 to 15 megatonnes of carbon dioxide equivalent per year.

The degree to which the estimated emissions associated with the additional capacity would be incremental depends on the considerations that drive investment decisions for crude oil producers, namely the expected price of oil, the availability and costs of other transportation modes (e.g., crude-by-rail), whether other pipeline projects are built, and costs of production.

[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.

If the Trans Mountain Expansion Project is the only project adding pipeline capacity in Western Canada and the netback price for the marginal barrel of oil sands production does not change with its construction, the project would not be expected to cause incremental production or upstream emissions. However, there are circumstances under which building only the Trans Mountain Expansion Project could result in improved financial returns (i.e., improved netback price) for proposed oil sands projects and, therefore, cause incremental production and upstream emissions.

If additional pipeline capacity, including the Trans Mountain Expansion Project, is built such that shipping large volumes of crude-by-rail was no longer needed, it is likely that the netback price on the marginal barrel of oil sands production would increase. A portion of the emissions calculated in this review would therefore be incremental.

Incremental production is likely to be greater 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. If long-term oil prices were expected to be lower than this range, significant new investment in oil sands production may not be expected regardless of the mode of transportation (i.e., rail or pipeline). In addition, if one assumes that a number of proposed pipeline projects are built, there are challenges associated with attributing any incremental GHG emissions to a specific pipeline since many proposed projects have similar construction timelines and capacities.

Incremental oil sands production could have an impact on global supply and prices. Some portion of this would displace different types of crude oil that would no longer be produced. In this case, the impact on global emissions would be the difference in well-to-tank GHG emissions between oil sands and the displaced crude oil. Some portion of any incremental production could also increase total global oil supply, lowering global prices and increasing the quantity of oil consumed globally. The emissions impact of this portion of incremental production would be the full well-to-wheels lifecycle emissions. Given that a substantial amount of crude oil is expected to be financially viable in a similar crude oil price range to Canadian oil sands, it is expected that a large portion of incremental production would displace other types of crude oil, rather than increase total oil supply.

Introduction

The Government of Canada is committed to ensuring decisions on proposed projects are based on science and evidence, including with respect to climate change. As part of its January 27, 2016 announcement of interim principles, the Government of Canada has committed to assess the upstream greenhouse gas (GHG) emissions associated with projects undergoing an environmental assessment (1).

Environment and Climate Change Canada (ECCC) recognizes the impacts of climate change are evident in every region in Canada. Recent reports on climate change, including the 2014 Report of the Intergovernmental Panel on Climate Change (2), emphasize impacts on water, fisheries, agriculture and forestry, human health, coastlines, and Arctic regions. In addition, Natural Resources Canada's report *Canada's Marine Coasts in a Changing Climate* (3) states that the largest amounts of relative sea-level rise in British Columbia are projected to occur on the Fraser Lowland, southern Vancouver Island and the north coast. Natural Resources Canada's report also states that sea-level rise presents a long-term threat by increasing the risk of coastal flooding. However, sea-level rise also increases the potential impact of storm-surge flooding because deeper nearshore water raises the height and energy of waves as they strike coastal structures. It is for this reason that Natural Resources Canada's report finds that storm-surge flooding presents a greater threat to coastal communities than sea-level rise alone. In addition to climate impacts on sea-level rise, marine ecosystems in British Columbia will be affected as species move northward in response to warmer water and changing precipitation patterns will affect summer water availability and the timing of salmon runs in some watersheds. British Columbia may be particularly vulnerable to ocean acidification over the long term relative to other coastal environments in Canada because the north Pacific is already very acidic. Ocean acidification is a major challenge for economically important, heavily calcified shellfish like abalone, oysters, mussels, clams and sea urchins. Any incremental emissions caused by a project will contribute to global climate change and its related impacts on the environment.

The following review of upstream GHGs for the Trans Mountain Expansion Project (the Project) includes a Project description, a quantitative estimation of the GHG emissions released as a result of upstream production associated with the Project (Part A), and a discussion of the Project's potential impact on Canadian and global GHG emissions (Part B).

Project Description

In operation since October 1953, the Trans Mountain Pipeline (TMPL) system 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 TMPL system has been increased a number of times.

The existing TMPL system 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 system. 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 (4):

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 (Trans Mountain) submitted an application for the Project to the National Energy Board (NEB). The Project would expand the existing TMPL system between Edmonton and Burnaby, increasing its nominal capacity from the current 300,000 bbl/d to 890,000 bbl/d. The Project would include (5):

- 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).

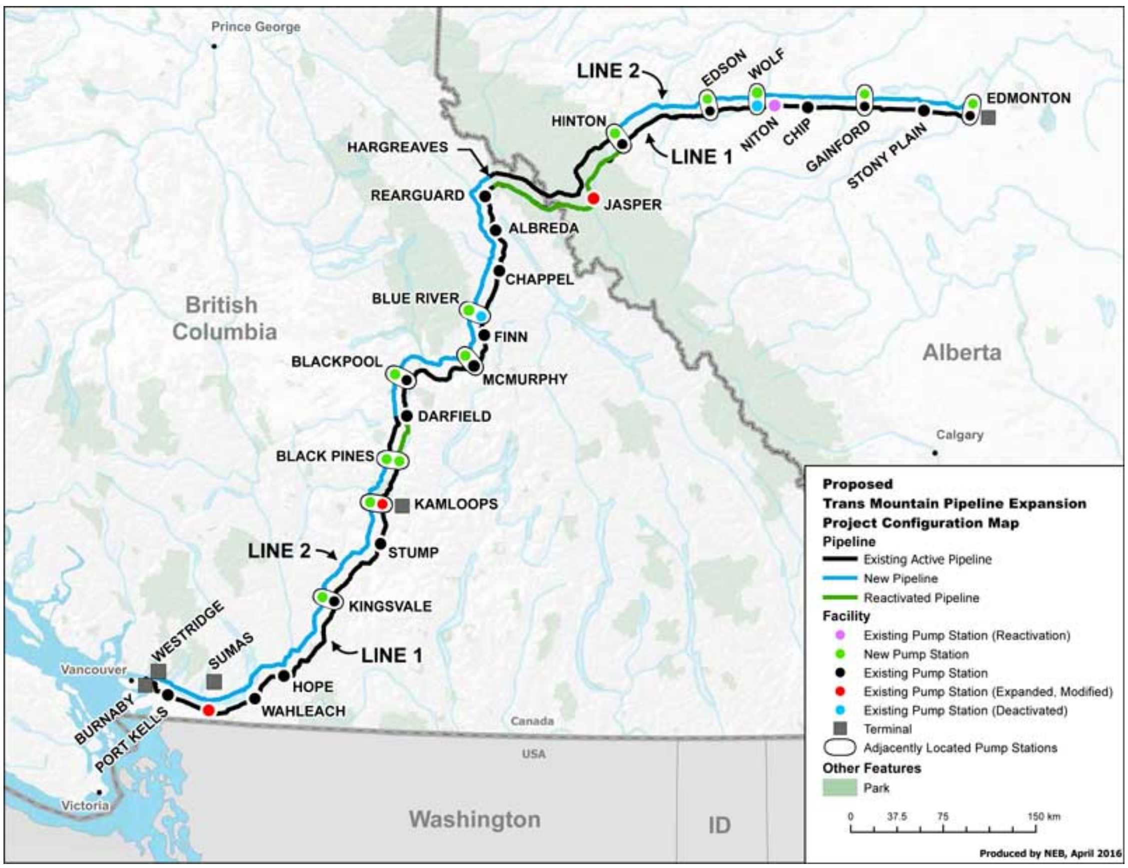
The Project would also require ancillary facilities as well as power lines and permanent access roads. Some temporary infrastructure would also be required during construction. The existing TMPL facilities, combined with the facilities proposed in the Trans Mountain Expansion Project, would result in two parallel pipelines. Line 1, consisting of the existing pipeline segments, would have a capacity of 350,000 bbl/d (an increase of 50,000 bbl/d over the existing capacity), and Line 2 would have a capacity of 540,000 bbl/d. Trans Mountain expects that the expanded Line 1 would provide transportation for refined products and light crude oil, but would also be capable of transporting heavy crude oil at a reduced capacity. The proposed Line 2 would provide transportation for heavy crude oil, but would also be capable of transporting light crude oil.

Trans Mountain has also considered a theoretical future expansion scenario which would add an additional 240,000 bbl/d of capacity to Line 2. There are however many obstacles to the viability of this expansion scenario, including the availability of power supply, the space available for tanks and terminal infrastructure, the capacity of the Puget Sound pipeline, and the capacity of the Second Narrows in Burrard Inlet for increased vessel traffic (6).

A map of the proposed TMPL system is shown below in Figure 1. Trans Mountain plans to begin construction in 2017 and put the expanded pipeline into service in 2019.

The operation-related GHG emissions of the expanded TMPL system have been estimated by Trans Mountain to be 407 kilotonnes (kt) per year of carbon dioxide equivalent (CO_2 eq) at full build (7). Additionally, GHG emissions as a result of project-related marine shipping have been estimated to be 68 kt CO_2 eq per year (8). These emissions are not considered as part of this assessment.

Figure 1: Project Map



Part A. Estimation of the Upstream GHG Emissions

A.1 Scope

Part A of this review provides quantitative estimates of the GHG emissions released as a result of upstream extraction, processing, and refining of crude oil associated with the Project. This includes emissions from combustion, industrial processes, flaring, venting, and fugitive sources. The GHG emissions from these sources contain carbon dioxide, methane and nitrous oxide. These constituents of GHG emissions were added together taking into account their respective global warming potentials. The scope of this review 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.

The analysis in Part A includes a number of limitations in terms of its scope. Currently, publicly-available data and established methodologies do not allow for the inclusion of estimates of GHG emissions related to land use changes caused by upstream oil and gas activities related to a specific project. As well, the GHG emissions related to the production, processing and transportation of fuels and electricity that are purchased for upstream oil and gas activities are not included due to data limitations. Further information related to these limitations is provided in Annex C.

The methods for extracting, processing, and refining different types of crude oil may vary; as a result, different types of crude oil 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 TMPL system will change during its operational life to reflect operational requirements and market demand. Due to the potential variability associated with the product mix, including the quantities and types of crude oil and refined products transported by the TMPL system, emissions estimates are presented for several potential scenarios.

Estimates of upstream GHG emissions related to the Project were modeled up to year 2030, based on available information. Without further information related to projected outcomes of environmental policy and technology implementation post-2030, it is challenging to estimate emissions for years beyond 2030. However, ECCC recognizes that the Project is likely to operate for longer than the 2030 timeframe included in this assessment. As an illustrative example of potential annual upstream emissions related to the Project for years post-2030, assuming no change in factors including environmental policies and technology implementation, annual upstream emissions related to the Project could remain within the range estimated for the year 2030 for each year of operation thereafter.

A.2 Project Capacity

Upstream emissions were estimated for the expanded TMPL system nominal capacity (Line 1 and Line 2, total of 890,000 bbl/d[ii]) as well as separately for the additional pipeline capacity that the Project could add to Line 1 (50,000 bbl/d) and Line 2 (540,000 bbl/d). The TMPL system is assumed to run at full capacity throughout the modelling period. Whether or not the estimated upstream GHG emissions associated with the additional pipeline capacity could result in incremental GHG emissions in Canada is

[i] The proportions of different categories of products (such as diluted bitumen or refined products) transported in the TMPL system 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.

not discussed in Part A of this review. A discussion of the implications on Canada's GHG emissions of the additional pipeline capacity that would be enabled by the Project is included in Part B[iii].

A.3 Product Mix

For the purposes of this review, the many different types of crude oil and refined products that could be transported by the expanded TMPL system were aggregated into the seven categories below. The product categories have been selected to allow for the use of emissions data from ECCC (9) and production trends from the NEB (10) to develop emissions factors (see section A.6 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. This type of crude oil requires that diluent be added in order to flow through pipelines; for the purpose of this review it was assumed that 8% of the volume of this type of crude oil is diluent.

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. It was assumed that 30% of the volume of this type of crude oil is diluent. Extraction involving the addition of solvent with steam is also included.

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. It was assumed that 30% of the volume of this type of crude oil is diluent. 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. It was assumed that 20% of the volume of this type of crude oil is diluent. 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.

[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.

A.4 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 TMPL system. 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 TMPL 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 Project (11). The report presents the expected throughput of products (receipts and deliveries) at each loading/unloading point along the expanded TMPL system. The following assumptions 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.3 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 (10).
- Line 2 is dedicated to transporting heavy oil only

The product categories from the report by the RWDI Corporation have been assigned to the product categories of this review according to the following table.

RWDI report	This review
Heavy	*Conventional Heavy* *CSS Heavy* *SAGD Heavy* *Mined Bitumen*
Light sour	*Conventional Light*
Light/synthetic	*Conventional Light* *Synthetic*
Refined	*Refined Products*

A.4.1 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 Project (12). The 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 review was obtained using generic data on blend type composition obtained from the NEB[v] and the Alberta Energy Regulator[vi] as per the following table.

Muse Stancil report (blend types)	**This review**
Sweet synthetic	*Synthetic*
Canadian Light Sweet/Medium Sour	*Conventional Light*
Cold Lake Blend	*Conventional Light* *Conventional Heavy* *CSS Heavy* *SAGD Heavy*
Athabasca Synbit	*Mined Bitumen* *CSS Heavy* *SAGD Heavy*
Athabasca Dilbit	*Mined Bitumen* *CSS Heavy* *SAGD Heavy*

In this scenario the throughput volume of heavy oil being transported varies throughout the modelling period, ranging from 370,000 bbl/d to 480,000 bbl/d. This is less than the capacity of Line 2. The remaining capacity of Line 2 was assumed to be transporting a blend of light crude oil, synthetic crude oil, and refined petroleum products.

A.4.2 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 (10).

A.4.3 Scenario 3

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

A.4.4 Scenario 4

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

[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

As an example, Table 1 provides the proportions of each product category in year 2020, for Scenario 2, for the two pipelines of the expanded TMPL system (Line 1 and Line 2).

Table 1: Product Mixes – Scenario 2 (Year 2020)

Product Category	Line 1 (%)	Line 2 (%)
Refined Products	13	-
Conventional Light	43	-
Conventional Heavy	-	30
CSS Heavy	-	13
SAGD Heavy	-	40
Mined Bitumen	-	17
Synthetic	45	-

A.5 Estimated Upstream GHG Emissions

The resulting range of estimated upstream GHG emissions associated with the Project is presented below in Table 2 for the four scenarios described above. For each scenario, estimates are provided for both the expanded nominal capacity of the TMPL system (890,000 bbl/d) and for the capacity that the Project could add to the system: Line 1 (50,000 bbl/d) and Line 2 (540,000 bbl/d). The methodology used to determine these emission estimates is described in the *GHG Forecast Approach* section below. Though calculation methodologies may differ, according to IHS CERA Inc. the estimated emissions from crude oil production would account for between 10% and 20%, while estimated emissions for refined products would account for between 20% and 30%, of the lifecycle emissions of the products transported by the TMPL system (13).

ECCC projects that the upstream GHG emissions in Canada resulting from the production, processing, and refining of products associated with the expanded nominal capacity of the TMPL system could range from 21 to 26 Mt of CO_2 eq per year. Considering only the capacity added by the Project, emissions could range from 13 to 15 Mt of CO_2 eq per year.

As illustrated in Table 2, the estimated upstream GHG emissions are significantly influenced by the product mix that will be transported by the expanded TMPL system. There is uncertainty in the actual product mix that will be transported and therefore, the actual associated upstream GHG emissions. As well, this part of the review (Part A) does not consider whether these emissions would occur in the absence of the Project. Given these inherent uncertainties, the values presented are estimates of a range of possible upstream GHG emissions associated with the Project.

Table 2: Estimated Upstream Emissions (Mt of CO_2 eq)

Year	System Capacity (Mbbl/d)	Scenario			
		1	**2**	**3**	**4**
2019	**890**	24.0	23.9	24.9	21.8
	Line 1: 50	*1.6*	*1.6*	*1.7*	*1.3*

Year	System Capacity (Mbbl/d)	Scenario			
		1	2	3	4
	Line 2: 540	*12.8*	*12.8*	*12.8*	*12.8*
2020	**890**	23.8	23.9	25.0	21.8
	Line 1: 50	*1.6*	*1.6*	*1.7*	*1.3*
	Line 2: 540	*12.4*	*12.7*	*12.7*	*12.7*
2021	**890**	24.0	23.9	25.0	21.8
	Line 1: 50	*1.6*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.5*	*12.7*	*12.7*	*12.7*
2022	**890**	24.0	23.9	25.0	21.8
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.4*	*12.6*	*12.6*	*12.6*
2023	**890**	24.1	23.8	24.8	21.6
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.4*	*12.5*	*12.5*	*12.5*
2024	**890**	24.5	23.6	24.7	21.5
	Line 1: 50	*1.7*	*1.6*	*1.7*	*1.3*
	Line 2: 540	*12.8*	*12.4*	*12.4*	*12.4*
2025	**890**	25.7	23.5	24.6	21.3
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*13.6*	*12.2*	*12.2*	*12.2*
2026	**890**	25.1	23.4	24.6	21.3
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*13.0*	*12.2*	*12.2*	*12.2*
2027	**890**	24.1	23.4	24.5	21.2
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.1*	*12.1*	*12.1*	*12.1*
2028	**890**	24.2	23.3	24.4	21.2
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.3*	*12.1*	*12.1*	*12.1*
2029	**890**	23.9	23.2	24.3	21.1
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*11.9*	*12.0*	*12.0*	*12.0*
2030	**890**	23.8	23.2	24.3	21.1
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*11.8*	*12.0*	*12.0*	*12.0*

A.6 GHG Forecast Approach

The estimates in Table 2 were developed using GHG emission projections from ECCC's *Canada's Second Biennial Report on Climate Change* submitted to the United Nations Framework Convention on Climate Change (UNFCCC) (9) and the NEB's production projections from the report *Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2040* (*EF 2016*) (10). ECCC used the details of the projected GHG emissions and productions that were specific to the *with current measures* reference scenario (9). 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.

A number of recently announced provincial government policies, such as those outlined in Alberta's *Climate Leadership Plan* (14) and British Columbia's *Climate Leadership Plan* (15), 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.

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 (16). The Government of Canada has also committed to reduce methane emissions from the oil and gas sector by 40% to 45% below 2012 levels by 2025.

On October 3, 2016, the Government of Canada proposed its pan-Canadian approach to pricing carbon pollution. Under the new plan, all Canadian jurisdictions will have carbon pricing in place by 2018. In order to accomplish this, Canada will set a benchmark for pricing carbon emissions—set at a level that will help Canada meet its greenhouse gas emission targets, while providing greater certainty and predictability to Canadian businesses. Provinces and territories will have flexibility in deciding how they implement carbon pricing: they can put a direct price on carbon pollution or they can adopt a cap-and-trade system. The government proposes that in provinces and territories with a direct price on carbon, the price should start at a minimum of $10 per tonne in 2018, rising by $10 each year to $50 per tonne in 2022. As carbon pricing will be based on GHG emissions and applied to a common and broad set of sources, the costs of activities that generate GHG emissions are expected to increase over time (17).

While this analysis focuses on policies implemented as of September 2015 and does not reflect the impact of additional federal, provincial, or territorial measures announced or under development, it is recognized that future improved practices will mitigate emissions. As measures to meet targets are implemented, they will be incorporated into future emissions projections and future upstream GHG reviews.

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

For the purposes of this review, 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 a specific emission factor that depends on the emissions generated during its extraction, upgrading, and refining, when and if applicable.

In order to develop emission factors, ECCC divided projected emissions for extraction, upgrading, and refining, as appropriate, by the respective production projection. The resulting emission factors are presented in Table 3. The methodology used to develop the emission factors is presented in Annex B of this review.

The unit volume for each product category was determined by taking into account the Project's expected capacity and expected product mix. Each product category's unit volume was adjusted (where applicable) to exclude the diluent portion associated with transporting that category of product. The total diluent volume transported by the TMPL system also has upstream emissions associated with its production. Most of the diluent is expected to be imported according to the NEB (10). Upstream emissions were only estimated for the portion of the diluent that is expected to be produced in Canada. The emission factors for conventional light crude oil were used for the diluent portion that is produced in Canada.

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

Year	Refined Products	Conv. Light	Conv. Heavy	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2019	87.8	68.5	85.9	82.3	75.1	44.1	105.1
2020	88.0	68.7	85.8	82.4	75.4	44.2	105.4
2021	88.2	69.0	85.8	82.4	75.8	44.4	105.9
2022	88.4	69.2	85.7	82.4	76.1	44.6	106.2
2023	88.5	69.3	85.7	82.4	76.1	44.7	106.3
2024	83.3	69.4	85.7	82.4	76.1	44.7	106.3
2025	83.6	69.5	85.7	82.4	76.1	44.7	108.0
2026	83.7	69.6	85.7	82.4	75.9	44.7	107.9
2027	83.7	69.7	85.7	82.5	75.8	44.7	107.7
2028	83.6	69.7	85.7	82.6	75.5	44.7	107.5
2029	79.1	69.8	85.8	82.7	75.4	44.7	107.4
2030	79.1	69.8	85.8	82.8	75.3	44.7	107.4

A.7 Facility-Reported Data

Emission factors for some crude oil categories can also be determined using facility-reported emissions and production data. For comparison purposes, ECCC also estimated upstream GHG emission using emission factors calculated from facility-reported data. Facility emissions were obtained from the federal *Greenhouse Gas Reporting Program* and the *Specified Gas Emitters Regulation* provincial regime in Alberta. Facility production was obtained from provincial reporting sources. The resulting range of estimated upstream GHG emissions associated with the Project is presented below in Table 4 for the four scenarios described in A.3 above. The results are largely the same as those estimated in Table 2.

Table 4 – Estimated Upstream GHG Emissions – Facility-Reported Data (Mt of CO_2 eq per year)

Year	System Capacity (Mbbl/d)	Scenario			
		1	2	3	4
2019	**890**	23.9	23.8	24.9	21.5
	Line 1: 50	*1.6*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.5*	*12.5*	*12.5*	*12.5*
2020	**890**	23.6	23.8	24.9	21.5
	Line 1: 50	*1.6*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.1*	*12.4*	*12.4*	*12.4*
2021	**890**	23.8	23.8	24.9	21.5
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.1*	*12.4*	*12.4*	*12.4*
2022	**890**	23.8	23.7	24.9	21.5
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.0*	*12.3*	*12.3*	*12.3*
2023	**890**	23.9	23.6	24.7	21.3
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.0*	*12.2*	*12.2*	*12.2*
2024	**890**	24.4	23.4	24.6	21.2
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.4*	*12.1*	*12.1*	*12.1*
2025	**890**	25.6	23.3	24.5	21.0
	Line 1: 50	*1.8*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*13.3*	*11.9*	*11.9*	*11.9*
2026	**890**	25.0	23.3	24.5	20.9
	Line 1: 50	*1.8*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*12.7*	*11.8*	*11.8*	*11.8*
2027	**890**	23.9	23.2	24.4	20.9
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*11.7*	*11.8*	*11.8*	*11.8*
2028	**890**	24.0	23.1	24.3	20.9
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*11.9*	*11.7*	*11.7*	*11.7*
2029	**890**	23.7	23.0	24.2	20.8
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*11.5*	*11.7*	*11.7*	*11.7*
2030	**890**	23.5	23.0	24.2	20.7
	Line 1: 50	*1.7*	*1.6*	*1.8*	*1.3*
	Line 2: 540	*11.4*	*11.7*	*11.7*	*11.7*

The emission factors calculated using facility-reported data are presented in Table 5. The methodology used to develop these emission factors is presented in Annex B of this review.

Table 5 – GHG Emission Factors – Facility-Reported Data (kg of CO_2 eq/barrel)*

Year	Refined Products	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2019	88.0	84.1	71.0	40.6	107.6
2020	88.2	84.1	71.3	40.7	108.0
2021	88.5	84.2	71.7	40.9	108.4

Year	Refined Products	CSS Heavy	SAGD Heavy	Mined Bitumen	Synthetic
2022	88.6	84.2	72.0	41.0	108.8
2023	88.7	84.1	72.0	41.1	108.8
2024	83.5	84.1	72.0	41.1	108.8
2025	83.9	84.1	72.0	41.2	110.6
2026	83.9	84.2	71.8	41.2	110.6
2027	83.9	84.2	71.7	41.1	110.4
2028	83.9	84.3	71.5	41.1	110.1
2029	79.3	84.4	71.3	41.1	110.0
2030	79.3	84.6	71.2	41.1	110.0

* It was not possible to use facility-reported data to calculate emission **factors for the *conventional light* and *conventional heavy* crude oil categories. For these crude oil categories, emission factors from Table 3 were used.**

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 TMPL system. 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 Project, or, for that matter with or without additional pipeline capacity more generally.

If the same quantity of oil production were expected to occur in the absence of the Project as in a scenario where the Project were built, the 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 was built, then there would be incremental upstream emissions in Canada. Given that incremental oil production will lead to incremental GHG emissions, these terms are used interchangeably in this review.

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

Part B is divided into three sections. The *Canadian Oil Production Outlook* section discusses the NEB's and ECCC's projections for future oil production and upstream GHG emissions growth, respectively, and Canada's climate commitments in relation to oil sands production growth, the global crude oil outlook, current and potential markets for oil sands growth, and oil market uncertainties. 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. Several limitations associated with the overall assessment in Part B are provided in Annex C.

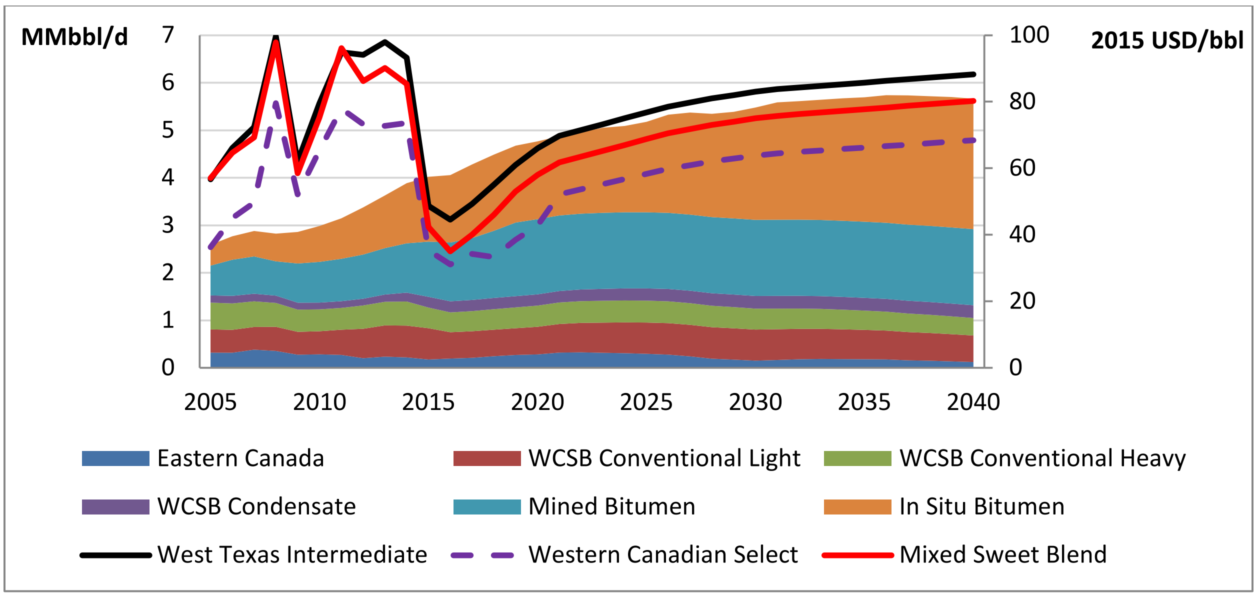
B.2 Canadian Oil Production Outlook

This section discusses the NEB's projections of Canadian oil production growth, ECCC's GHG emissions projections, the global outlook for oil, and the potential markets for Canadian crude oil. It then discusses oil market uncertainties and concludes with a discussion of the NEB's *Constrained Pipeline* case from the report *Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2040* (*EF 2016*) (10) and the potential implications for Canada's GHG reduction commitments for oil sands growth.

B.2.1 Canadian Oil Supply Growth

In 2015, Canada produced an estimated 4.0 million barrels per day (MMbbl/d) of crude oil, of which 2.5 MMbbl/d, or approximately 63%, was from the oil sands. According to the *Reference Case* in the NEB's *EF 2016 Update* report, oil production in Canada is expected to increase by 41% and reach 5.7 MMbbl/d by 2040. The NEB estimates that 77% (or 4.3 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 72% increase from 2015 levels by 2040 (See Figure 2) (18). Most production forecasts, including the NEB's *Reference Case*, *High Price Case*, and *Low Price Case*, assume pipeline capacity will be built as required.

Figure 2: Total Canadian Crude Oil and Equivalent Production and Oil Price Forecast (*Reference Case*)



Source: NEB (18)

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 Update Reference Case*, the price of West Texas Intermediate (WTI) – a North American crude oil benchmark – averages USD 49/bbl ($2015) in 2015, increasing to USD 66/bbl in 2020, and finally reaching USD 88/bbl by 2040. Western Canadian Select (WCS), the benchmark heavy crude oil from Western Canada, is priced on average USD 19/bbl lower than WTI over the projection period, while Canadian Mixed Sweet Blend (MSW), the benchmark light crude oil from Western Canada, is priced on average USD 8/bbl lower than WTI.

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

The *EF 2016 Update* also examines a *Low Price Case* and a *High Price Case* and presents the impact on Canadian crude oil production. In the *Low Price Case*, the WTI crude oil price is on average USD 34/bbl ($2015) lower than the *Reference Case*, reaching USD 48/bbl by 2040. In the *High Price Case*, the WTI crude oil price is on average USD 29/bbl higher than the *Reference Case*, reaching USD 128/bbl by 2040. In the *Low Price Case*, oil sands production grows marginally after projects currently under construction are completed, and reaches 3.5 MMbbl/d in 2040, approximately 19% lower than the *Reference Case*. In the *High Price Case*, oil sands production reaches 5.1 MMbbl/d in 2040, approximately 18% higher than the *Reference Case* (18).

Despite the current low oil price environment, the NEB expects that most production growth in the oil sands up to 2020 will remain unaffected due to the contributions from recently completed oil sands projects and those presently under construction. The NEB does note that between 2019 and 2022 *in situ* oil sands production growth is expected to be slower than previously forecast in *EF 2016* resulting from project deferrals and cancellations, though as the price of crude oil crude increases in the *Reference Case* production increases as a result of improved project economics. Forecasts from the Canadian Association of Petroleum Producers (CAPP) and the Alberta Energy Regulator (AER) also show that most oil sands supply growth to the end of the decade can be considered 'locked in', and is unlikely to be reduced by a significant amount. ECCC estimates around 480,000 bbl/d of oil sands capacity is expected to finish construction and come online between 2016 and 2019 (see Table in Annex D). After including the necessary diluent for transporting diluted bitumen, additional pipeline-grade product available for transport by 2020 increases to nearly 590,000 bbl/d[viii].

B.2.2 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* (9). 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).

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 are expected to 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 (9).

[viii] Much of the estimated 480,000 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 588,800 bbl/d of pipeline grade oil sands production.

B.2.3 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 (19). In its *New Policies Scenario*, the International Energy Agency (IEA) projects world crude oil and liquids 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 and natural gas liquids 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.

Countries from the Organization for Economic Cooperation and Development (OECD) are expected to continue to experience structural declines in crude oil and natural gas liquids demand, with the IEA estimating an average annual decline of 1.2%. Respectively, Japanese, European, and U.S. demand for oil and natural gas liquids 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 and liquids 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 (19).

B.2.4 Current and Potential Markets for Canadian Oil Sands Production Growth

B.2.4.1 Current Markets

In 2015, 99% of Canadian crude oil exports went to the U.S. The U.S. is divided into five petroleum markets termed Petroleum Administration 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 2015, refineries in PADD 2 processed 3.6 MMbbl/d of oil which represented 22% of U.S. crude oil consumption (see Table 6) (20) (21). In addition, PADD 2 refineries use large volumes of heavy oil as inputs. In 2015, refineries in PADD 2 processed 1.5 MMbbl/d of heavy oil, or about 33%, of all U.S. heavy oil refinery inputs, and of this, 1.46 MMbbl/d was heavy oil from Canada. Exports to PADD 2 accounted for 67% of all Canadian heavy oil exports in that year[ix].

[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.

Table 6: U.S. Oil Receipts, and Canadian Exports by PADD in 2015

	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)	1.1	7%	0.2	4%	0.1	5%
PADD 2 (Midwest)	3.6	22%	1.5	33%	1.46	67%
PADD 3 (Gulf Coast)	8.5	52%	2.2	49%	0.38	17%
PADD 4 (Rocky Mountains)	0.6	4%	0.2	4%	0.19	9%
PADD 5 (West Coast)	2.4	15%	0.4	9%	0.06	3%
U.S. Total	**16.2**		**4.4**		**2.2**	

Source: CAPP forecast based on data from the U.S. Energy Information Administration (22) and the NEB (10).

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 (12). As such, growth in Canadian oil sands production is more likely to be transported to markets other than PADD 2.

B.2.4.2 Potential Markets for Canadian Oil Sands Growth

If constructed, the Project would provide Canadian oil producers with access to potential refinery markets in the Pacific basin, including China and the Western U.S. Given the expected growth in heavy oil production in Canada, the potential for heavy oil processing in the Pacific basin 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 (23)[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 (24). 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. (25) and Muse Stancil & Co. (12) indicate that the most likely markets with existing ability to process Canadian heavy oil in the Asia Pacific market are California, China, Japan, and South 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 (12). Estimates from Muse Stancil & Co. and RWDI produced for the project applicant indicate that the expanded Trans Mountain pipeline would carry a substantial amount of diluted bitumen (12). 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.

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

While the Pacific market offers opportunities for Canadian crude oil, Canadian production will have to compete for refinery space. Currently, light and medium Middle Eastern crude oil are the primary sources of imports in the Pacific market (12). 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 (25) (26) (27). 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 (28) (29). 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 (19) (30). Despite competition from other suppliers, the Muse Stancil & Co. analysis undertaken for Trans Mountain suggests that the Pacific market could absorb crude oil carried on the TMPL system (12). Specific markets in the Pacific basin are discussed below.

B.2.4.2.1 China

China has the largest amount of refining capacity in Northeast Asia at approximately 8.3 MMbbl/d, and significant capacity to process heavy oil (23) (31)[xi]. In addition, 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 (26) (31). 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 (26) (32) (33). 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 (12) (29)[xii]**.** In addition, China has arrangements to provide loans to Venezuela in exchange for crude oil (34).

B.2.4.2.2 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 (12). Japan is a large refining market with a total refining capacity of 3.9 MMbbl/d. Muse Stancil & Co. 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 the TMPL system (12).

B.2.4.2.3 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 (12) (23). In 2013, several South Korean refineries added up to 0.3 MMbbl/d of heavy oil processing capacity (25). 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

[xi] China had approximately 1.3 MMbbl/d of coking capacity in 2010 (31).
[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 (12).

investments accordingly (35). Given the current configuration of South 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 the TMPL system (35).

B.2.4.2.4 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 2015, which represented 15% of total US crude oil consumption. Some California refineries are equipped to process heavy oil due to the large volumes historically produced in the state (25) (36). 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.2.4.2.5 PADD 3

PADD 3 includes refineries in the U.S. Gulf Coast and is one of the largest refining markets in the world. In 2015, refineries in PADD 3 processed 8.5 MMbbl/d of crude oil (20) (22). PADD 3 is the largest U.S. market for heavy crude oil, processing approximately 2.2 MMbbl/d, or 49% of heavy crude in the U.S. in 2015. Despite being a major market for crude oil, in 2015, PADD 3 refineries sourced only 4.5%, or 0.4 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 (16%) of total crude consumed in 2015 (10) (22). While PADD 3 is not a destination market for crude oil and products that would be transported on the TMPL system, 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.2.5 Oil Market Uncertainties

B.2.5.1 Oil Prices

WTI crude oil prices have declined significantly since the summer of 2014, from a high of USD 107/bbl in June 2014 to as low as USD 26/bbl in February 2016, and averaged USD 40.84/bbl to October 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 increase output levels in the face of these developments. At current prices (October 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 (38). For example, the NEB reported that over 700,000 bbl/d of oil sands capacity not yet under construction has been cancelled or delayed in recent years, most with start-up dates in the post-2020 timeframe (39).

[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 (25). 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.

B.2.5.2 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 (10). Pipeline constraints and resulting price differentials caused many companies to invest in crude-by-rail capacity between 2012 and 2014 (discussed below).

At this time, many pipelines from the Western Canadian Sedimentary Basin (WCSB) are at, or nearing, their effective capacities as evidenced by recent pipeline apportionment[xiv]. The NEB's *Canada's Pipeline Transportation System 2016* report (40) notes that oil export pipeline capacity was tight in 2015, citing increases in crude oil production from the oil sands and lack of additional pipeline capacity as the major contributing factors. According to the NEB, many of the major exporting oil and liquids pipelines (including Enbridge Mainline, the TMPL system, and Keystone) had average utilization rates above 85% in 2015. IHS Inc. estimates that exports from the WCSB could reach effective pipeline capacity by 2017, resulting in greater movements of crude-by-rail (41). Current pipeline projects, including the Trans Mountain Expansion Project, which have been proposed to and/or approved by the NEB have a cumulative capacity of over 3.4 MMbbl/d (22).

B.2.5.2.1 NEB Constrained Oil Pipeline Capacity Case (*Constrained Case*)

As part of the *EF 2016 report*, the NEB examined 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, expanded TMPL system, and Energy East) are built; however, the Enbridge Line 3 Replacement Program is completed. As such, the *Constrained Case* assumes that the Enbridge Mainline expansions and crude-by-rail are the only options available to transport Western Canadian crude oil production growth. Further, the NEB analysis, like this review, 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.2.4.2).

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

[xiv] In its fourth quarter 2015 Management's Discussion and Analysis (67), Enbridge Energy noted that the Mainline pipeline network remained under apportionment and was expected to be so into 2016. However, recent financial reports indicate that, at this time, the *Mainline System* is not under apportionment as a result of recent expansion projects by Enbridge Energy. The Trans Mountain pipeline has been under apportionment for a number of years. Apportionment occurs when the total desired amount of crude oil transportation space exceeds the available shipping capacity for that type of crude oil on a pipeline. The space on a pipeline under apportionment is rationed between bidding parties, typically on a pro-rata basis. 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.

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.2.6 Canadian Climate Change Commitments and Oil Sands Production

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

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

Some studies have presented scenarios where oil sands production growth is not fully consistent with a world in which global warming is limited to 2°C. For example, a 2014 study found that Canadian bitumen production could increase to 4.1 MMbbl/d in 2035 and be consistent with a 2°C target, but only with a rapid deployment and scale-up of carbon capture and storage (CCS) technology from 2020 and the decarbonization of energy inputs (42). 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 (43).

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* (19). 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 (44).

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 (45).

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 review uses a forecast based on the NEB's *EF 2016 Update* report 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 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 (46). 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 instead, 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 applicant has made as a part of their submission to the NEB.

The following 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

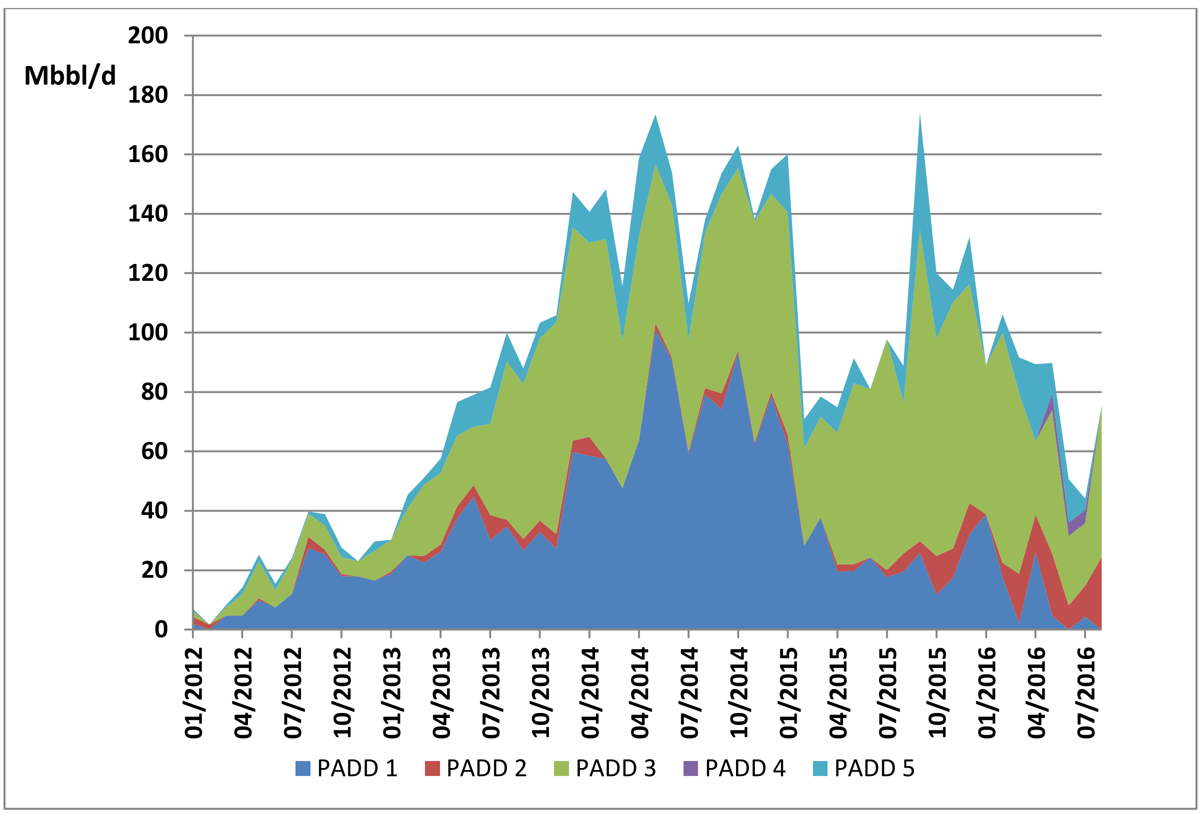
Since 2011, exports of crude oil by rail from Canada to the U.S. have increased substantially, from an average of about 2,000 bbl/d in 2011 to approximately 110,000 bbl/d in 2015. Crude-by-rail export volumes peaked at nearly 175,000 bbl/d in September 2015, and declined to 75,000 bbl/d in August 2016 (47).

While crude-by-rail exports from Canada were initially spread fairly evenly between PADD 1 and PADD 3, the destination for exports shifted towards PADD 3 in 2015 and has continued to be concentrated in this region in late 2016. These figures do not include crude-by-rail volumes transported within Canada (see Figure 3).

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 approximately 91,000 bbl/d in 2011 to 632,000 bbl/d in 2015 as a result of light tight oil production growth from the Bakken fields in North Dakota. Since mid-2015, crude-by-rail shipments in the U.S. have declined. This is a result of low crude oil prices which have led to decreases in output from some U.S. shale oil basins as well as more pipeline capacity being added from some basins (48).

Figure 3 - Canadian Crude-by-Rail Exports by PADD, monthly 2011-2016



Source: U.S. Energy Information Administration, Crude Oil Movements of Crude Oil by Rail (47)

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

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

A key question when considering if crude-by-rail is a viable alternative to pipelines is 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 (49). 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 primarily by smaller crude oil producers, crude-by-rail has served as an alternative for companies as pipeline constraints and price differentials increased. Estimates indicate that crude-by-rail loading capacity in Alberta and Saskatchewan is 1.1 MMbbl/d (50)[xvi]. In the U.S., crude-by-rail offloading capacity is concentrated in PADD 1 and PADD 3. Recent estimates from RBN Energy indicate that nearly 1.7 MMbbl/d of rail offloading capacity currently exists in PADD 3 (51). 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 1.6 MMbbl/d, concentrated in the Bakken fields of North Dakota (49).

Crude-by-rail capacity figures are not directly comparable with pipeline capacity figures. When bitumen is produced, it is either upgraded to synthetic crude oil (typically production from oil sands mines) or blended with a diluent to enable it 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 which reduces the costs per barrel of bitumen transported and decreases the financial impact of differences in diluent value between the origin and destination markets (52). Alternative bitumen blends hauled on rail are *railbit* (15-20% diluent) or *rawbit* (0-2% diluent). Transporting *rawbit* requires special tanker cars and loading and offloading facilities, which are not widely used at this time (52).

B.3.3 Relative Costs of Pipelines and Rail

This review 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 with varying pipeline construction assumptions. Under the baseline scenario, it is assumed that the primary market for Canadian production growth would be PADD 3 (U.S. 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

---

[xvi] The Department of State Final Supplemental Environmental Impact Statement (KXL FSEIS) Market Analysis notes data from the North Dakota Industrial Commission (66) that indicates effective rail capacity at around 80% of nameplate capacity.

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 the TMPL system is expanded, 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 oil sands projects that have no other option but to use rail would be expected to decline and 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 expanded TMPL system 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 7)[xvii]. By comparison, transporting diluted bitumen on the TMPL system from Alberta to the Port of Vancouver, and then shipping it by Aframax tanker to key Pacific basin refining centres is expected to cost between USD 7.50/bbl and USD 11.50/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 the 890,000 bbl/d of total planned capacity on the expanded TMPL system would be under committed contracts with shippers, leaving the remaining capacity for uncommitted shippers (53).

The estimated pipeline tolls for the TMPL system are based on Trans Mountain's NEB filings while the tanker rates from Westridge, British Columbia to Asia and California were adapted from estimates provided by Muse Stancil & Co. as part of Trans Mountain's submission for the Project (54)[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 10.00/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 $8.00/bbl of diluted bitumen.

[xvii] Rail rates assume pipeline transportation to Edmonton and rail to final destination.
[xviii] Muse Stancil (12) assumes that all crude oil shipped on the TMPL system is transported from the Westridge marine terminal 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 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. ECCC adjusted pipeline tolls from the draft assessment to reflect the increase in capital costs to $6.8 billion based on information provided in NEB filings.

Table 7: 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	TMPL system Committed/Tanker	$10.00
	TMPL system Uncommitted/Tanker	$11.50
Tsingtao, Northern China	TMPL system Committed/Tanker	$10.00
	TMPL system Uncommitted/Tanker	$11.50
Yosu, South Korea	TMPL system Committed/Tanker	$9.50
	TMPL system Uncommitted/Tanker	$11.00
Chiba, Japan	TMPL system Committed/Tanker	$9.50
	TMPL system Uncommitted/Tanker	$11.00
Los Angeles, California	TMPL system Committed/Tanker	$7.50
	TMPL system Uncommitted/Tanker	$9.00

Source: ECCC, U.S. Department of State (49), Muse Stancil (12), Trans Mountain Pipeline ULC (55)

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 which rail was the only transportation option, producers may have further incentive to invest in facilities to enable increased transportation of railbit or rawbit. [xx]
2) It 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 $8.00/bbl cost difference does not incorporate tax or royalty considerations, which would decrease the relative difference in transportation costs in after-tax terms.

[xx] 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.

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 of crude-by-rail are discussed in CAPP's 2015 crude oil forecast (22).

In addition, crude oil price differences between the Asia Pacific and PADD 3 markets could increase revenues for producers shipping on the TMPL system, 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 expanding the TMPL system could lead to higher Canadian oil sands production growth and associated emissions. It considers two scenarios: 1) no additional pipeline capacity from 2015 capacity levels is built besides expanding the TMPL system, and 2) other additional pipeline capacity, as well as the expanded TMPL system, is built such that exporting large volumes of crude-by-rail is no longer needed[xxii]. 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 is shipped by rail. The key difference between these scenarios and the baseline is the expected cost of transporting the marginal barrel of oil sands production from the WCSB.

The conclusions from these scenarios are driven by the degree to which the netback price for the marginal barrel of oil sands production could be affected[xxiii]. As illustrated below, incremental oil sands production could be enabled if the cost of transporting the marginal barrel of oil sands decreases, increasing the netback price of the marginal barrel of oil sands between the baseline scenario and the pipeline scenarios. An increase in netback price would improve the profitability of future oil sands projects and increase the likelihood of incremental production.

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 or under construction would be transported by rail. If future projects are expected to be sufficiently profitable when transporting crude-by-rail, they would proceed in the baseline. The netback price in Alberta for the marginal barrel of oil sands production would be the benchmark price (e.g., Western Canadian Select for heavy sour crude oil), less the cost of transportation by rail.

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

In a scenario where the Project is built, but no other additional pipeline capacity from the WCSB is built, there are two potential outcomes: **1A)** the netback price of the marginal barrel of oil sands could remain the same as under the baseline scenario, or **1B)** it could increase relative to the baseline.

1A) A portion of the oil sands production growth currently under-construction and/or some portion of crude oil export volumes currently transported by rail could shift to the additional pipeline capacity

[xxii] 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.

[xxiii] The netback price of oil in Alberta is the market price less the transportation costs associated with shipping the next barrel of oil.

(590,000 bbl/d) available on the Project. Since more production capacity is under construction and currently transported by rail than could be carried on the Project, the marginal barrel of oil sands produced could move by rail regardless of whether the pipeline is built. Under these circumstances, the netback price for the marginal barrel of oil sands in Alberta may not change.

If that were the case, the construction of the Project would not result in *incremental* production in Canada because the decision to produce an additional barrel from the oil sands would be based on the same netback price both with and without the Project.

1B) It is possible that the netback price of the marginal barrel of oil sands production could increase if the Project were the only pipeline capacity built from Western Canada. For example, building a pipeline could alter the end-markets for some types of crude oil, changing the marginal cost of transportation, or improving the overall efficiency of the North American crude oil transportation network. These examples could result in lower transportation costs, higher crude oil netback prices for the marginal barrel of oil sands production, and improved financial performance for future oil sands projects. In this case, the Project could enable incremental production and upstream emissions. A more complex quantitative examination of the issue would be required to model whether any of these circumstances could occur if the Project were built. Results from third party studies on this potential outcome are discussed below.

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

If the Project and other pipelines were built such that large-scale rail shipments of crude oil were no longer needed to transport the marginal barrel of oil sands production, then the netback price of the marginal barrel of oil sands production would increase. Previously unprofitable oil sands projects could become profitable resulting in an increase in production and upstream GHG emissions relative to the baseline. However, attributing any particular portion of these incremental upstream emissions to the Project, or any specific pipeline project, would be difficult. Rather, it would be attributable to the overall expansion of the Canadian pipeline transportation system.

To understand the degree to which incremental production could be added as a result of additional pipeline capacity under these scenarios (i.e., Scenario 1B, and Scenario 2), it is necessary to examine the economics of new investments in the oil sands.

B.4.4 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, transportation costs, taxes, and royalties and earn a rate of return on investment (usually 10-15%) (10). Supply costs are directly related to the netback price received in Alberta. If the netback goes up, the supply cost decreases, and vice versa.

For ease of comparison, supply costs are usually adjusted to a benchmark crude oil hub price, such as WTI or Brent, and reported in USD. For the purposes of this review, supply cost estimates are benchmarked to Canadian light oil at Edmonton, Alberta and presented in USD. The netback price in

Alberta is a key input in determining the supply cost, with lower transportation costs resulting in lower supply costs.

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 (56)[xxiv,xxv]. *In situ* project supply costs range between USD 45/bbl and USD 80/bbl WTI equivalent while mine project supply costs range between USD 80/bbl and USD 90/bbl WTI equivalent[xxvi]. 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. While they are left constant for the purposes of this analysis, it is important to consider that supply costs are not static, and are likely to change over time as market conditions evolve. For example, recent analysis from IHS indicated that oil sands supply costs decreased by as much as USD 10/bbl between 2014 and 2015 owing to lower construction costs resulting from the recent oil price decline, and lower natural gas costs (41).

To assess the impacts of transportation options on oil sands supply costs, ECCC uses a supply curve generated from its in-house oil sands project model. The supply curve is based off of publicly available information on over 125 *in situ* oil sands project phases that have been announced, are awaiting approval or have been approved by the Alberta Energy Regulator (referred to as *potential in situ* oil sands capacity), but 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 USD 70/bbl assuming pipeline transportation to Asia via the TMPL system (see Figure 4). Based on the incremental cost estimates for transporting crude oil by rail above (+USD 8/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 USD 80/bbl where producers used rail to PADD 3 rather than shipping diluted bitumen via the TMPL system[xxvii].

B.4.4.1 Comparing a Supply Curve to a Production Forecast

The supply curve 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 4 MMbbl/d, this does not mean that all of these projects will come online.

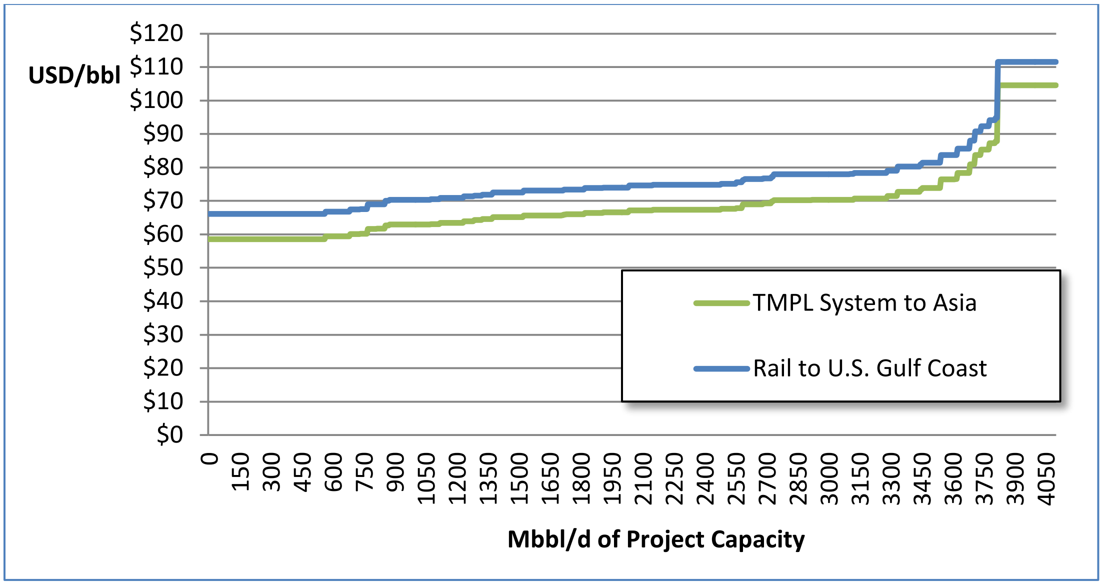
[xxiv] IHS (2015) *Oil Sands Cost and Competitiveness*

[xxv] Wood Mackenzie (2016): GEM Tool

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

[xxvii] Key assumptions (exchange rates, price differentials) that drive the oil sands model were taken from the NEB (10). 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 $6.50/bbl, a required rate of return of 12% (nominal), cost and commodity price inflation of 2% per year, no cogeneration at facilities, an average utilization rate of 75%, and Alberta's climate policy at $30/tonne CO_2 eq (nominal) on 20% of emissions.

Figure 4 - 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 4 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 drove 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. As such, many of the projects included in ECCC's oil sands supply curve will likely remain undeveloped.

Remodeling the supply curve to reflect the difference in transportation costs between rail and the TMPL system to Asia is done to illustrate the change in costs, but should not be interpreted as the Project lowering the supply costs of all potential *in situ* projects in the future. However, comparing supply curves for rail and pipelines can illustrate the potential for capacity additions at a specific long-term oil price. For example, if the Project were built, the supply curves above indicate that at an assumed price of USD 70/bbl around 1.9 MMbbl/d of future oil sands production capacity could be financially viable that may not have been viable if crude-by-rail were the only option.

While the change in netback price for the marginal barrel of oil sands production influences whether adding pipeline capacity would cause incremental production, the expected price of crude oil influences the degree of incremental production and upstream emissions.

B.4.4.1.1 Low Prices

If long-term Canadian light oil prices were below USD 60/bbl in real terms, there is unlikely to be substantial oil sands production growth post-2020 without a significant decrease in production costs from current levels, regardless of whether transportation was by rail or pipeline. An example of this low growth is the *EF 2016 Update Low Price Case* discussed above that has Canadian light oil prices growing to USD 33/bbl by 2025, and USD 40/bbl by 2040. In this case oil production grows by approximately

125,000 bbl/d to 2026 after projects currently under construction are completed (i.e., after 2020) and declines thereafter, 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.4.4.1.2 Mid-Range Prices

If long-term Canadian light oil prices were between USD 60 and USD 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 (~3.3 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 Project were completed, is considered to result in incremental upstream GHG emissions. If incremental rail costs are lower than the USD 8/bbl estimated transportation difference, the amount of incremental production and associated incremental upstream GHG emissions would be lower.

B.4.4.1.3 High Prices

If long-term Canadian light oil prices were greater than USD 80/bbl in real terms, a number of projects would likely be 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 *EF 2016 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. In reality, this effect may be marginal given the availability of capital in global financial markets (i.e., companies do not need to rely on internally generated cash flow to support capital investment). As such, incremental production is expected to be minimal at light oil prices above USD 80/bbl compared to a scenario where prices are in the USD 60-80/bbl range.

B.4.4.2 Incremental Emissions and Third Party Studies

Given the significant number of oil sands projects that could become economic with prices between USD 60 and USD 80/bbl there is greater potential for incremental production resulting from pipeline construction if long-term prices were in that range (see Table 8). However, the supply cost range (USD 20/bbl) is larger than the potential transportation cost savings (~USD 8/bbl). As such, the potential transportation cost savings the Project could generate would not affect production decisions within the entire USD 60-80 price range. While 3.3 MMbbl/d of potential cumulative capacity could become financially viable at long-term oil prices between USD 60-80/bbl, the total amount of potentially affected production would be less than this.

Table 8: Potential Incremental Oil Sands Production in Canada

	Long-term Price		
	<$60	**$60-80**	**>$80**
Oil Sands Growth	Limited to no growth in oil sands production	Limited growth in oil sands production	Growth in oil sands production
Incremental GHG Emissions as a result of pipelines	Less Likely	Potential	Minimal
Potential *cumulative* oil sands supply with a supply cost in the price range (post-2020)	~0 MMbbl/d	~3.3 MMbbl/d	~4.1 MMbbl/d

Source: ECCC

Several reports and studies have examined the GHG impacts of various pipeline projects. These studies have included an assessment of, or an assumption to inform, the amount of incremental production that could result from building a pipeline project. These reports illustrate that whether pipelines are shown to cause incremental crude oil production is largely determined by the assumptions guiding the analysis, including those related to the availability and cost of crude-by-rail, the potential for other crude oil pipelines to be built, oil price and other factors.

A report from Navius Research examined a portion of the greenhouse gas impacts of the TMPL system. The report indicates that incremental production resulting from the expansion of the TMPL system could be between 11% and 29% of the pipeline's additional capacity, or between 65,000 bbl/d and 171,000 bbl/d based on the scenarios examined (57). This is a slightly larger proportion of incremental production than in Navius Research's report on the proposed Energy East pipeline which estimated that between 3% and 9% of the proposed project's capacity could be incremental production (58).

Muse Stancil & Co.'s report concludes that building the proposed pipeline would lead to higher crude oil prices in Western Canada (12). Though the report does not offer an assessment of potential changes in crude oil production from building the pipeline, it highlights that the Project could change the marginal cost of transportation from Western Canada by reducing the reliance on crude-by-rail. This result would be expected to improve the financial performance of new oil sands investment in Western Canada which could result in incremental production.

Furthermore, *EF 2016* provides insight into the potential for incremental production from the addition of a number of new crude oil pipelines. NEB figures indicate that production could be 8% to 17% higher in 2040 in the *Reference Case* in which pipelines are built as needed relative to its *Constrained Pipeline Scenario* (10).

A number of other studies have analyzed upstream emissions from crude oil pipelines, but have typically made assumptions about the degree to which the projects could cause incremental production. These assumptions have ranged between 0% and 100% and have varied based on the factors noted above.

B.4.5 Global Oil Consumption and Upstream GHGs

If additional pipeline capacity in Canada were to enable incremental Canadian production growth, this could have two impacts on global crude oil markets: 1) a portion of this incremental production could displace different types of oil that would no longer be produced, and 2) the remaining portion could add to the overall global supply at a given price, which could result in a slightly lower global crude oil price, and greater global crude oil consumption over time.

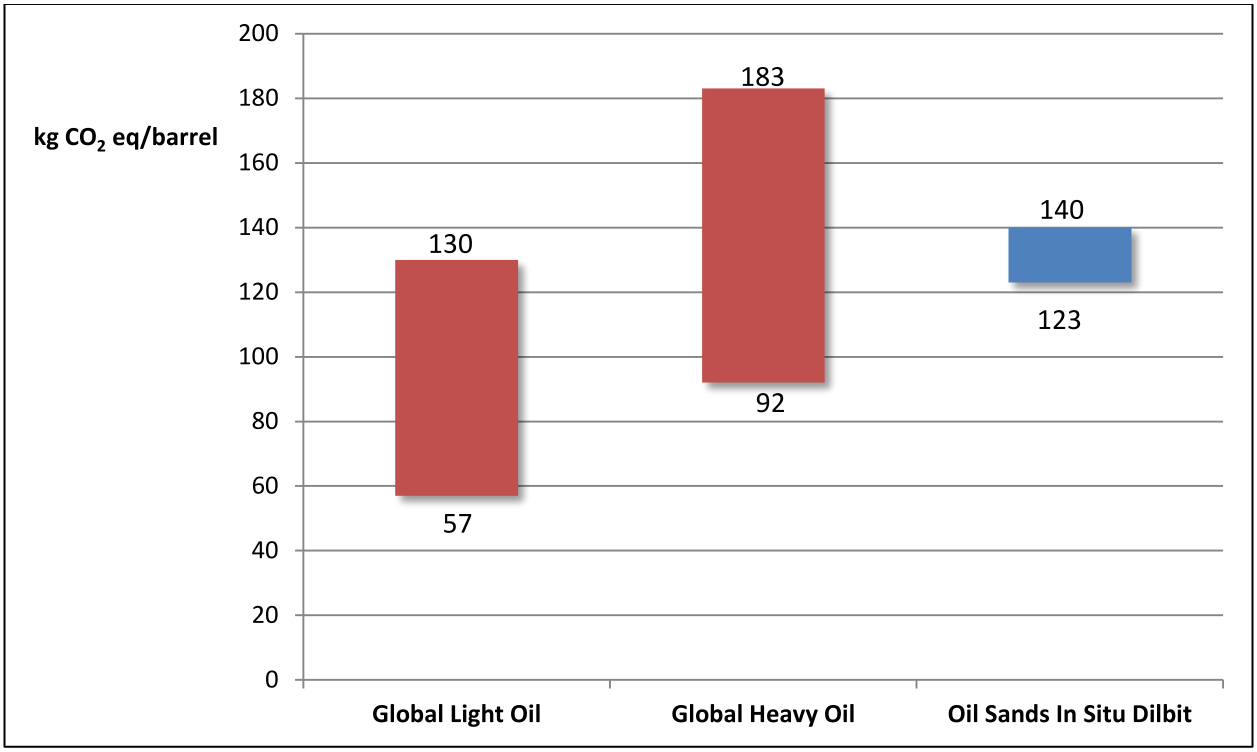
Where incremental oil sands production displaces other crude oil production that would have been produced in the baseline, the global GHG emissions impact would be the difference in well-to-tank (WTT) emissions between oil sands production and the crude oil that was displaced. A report from IHS Cambridge Energy Research Associates (CERA) argued that oil sands production on the proposed Keystone XL pipeline would have merely displaced other heavy oil, typically with comparable WTT emissions, resulting in a small impact to global emissions (59). While this conclusion is logical when discussing conditions in the PADD 3 market and U.S. emissions impacts, the global impact on emissions would depend on the type of crude oil that would no longer be produced globally.

Comparing WTT data from IHS CERA for a variety of crude oil types illustrates the wide range of potential emissions impacts. IHS CERA estimates that WTT emissions are 57 to 130 kg CO_2 eq per barrel for light crude oil, 92 to 183 kg CO_2 eq per barrel for other types of global heavy crude oil, and 123 to 140 kg CO_2 eq per barrel for oil sands in situ dilbit (Figure 5).

Where incremental Canadian oil sands production leads to an increase in global oil supply, the accompanying decrease in global crude oil prices could have an impact on global crude oil consumption. The global GHG emissions impact with this effect would be the total lifecycle emissions of oil sands in situ dilbit, from well-to-wheels (WTW). WTW data from IHS CERA indicate that WTW GHG emissions from oil sands in situ production range between 508 and 525 kg CO_2 eq per barrel of production.

A comprehensive report on the proposed Energy East pipeline by Navius Research found that, although most of the incremental production would displace existing global supply, it is the potential increase in global consumption that would likely have a larger impact on global emissions. The report found that, even with only a slight increase in total global crude oil supply, the effect of lower global oil prices increasing consumption over time led to 74% to 87% of the net emissions impact of the proposed Energy East pipeline in 2035 (60). The magnitude of this impact, relative to the impact in which other types of crude oil are displaced, is logical since tank-to-wheel emissions from combustion represent between 70% and 80% of the total WTW GHG emissions (13).

Figure 5 - Well-to-Tank GHG Emission Intensity Ranges by Type of Crude Oil[xxviii]



Source: IHS CERA

It is important to consider circumstances influencing the degree to which incremental Canadian oil sands production displaces existing sources of, or adds to total, global crude oil supply. The magnitude of the increase in global oil supply depends on the slopes of the global supply and demand curves around the point of equilibrium. In general, the more elastic the global supply curve (i.e., the flatter the crude oil supply curve or the more oil supply available within a given price range), the higher the proportion of incremental oil sands production that would be expected to displace other types of crude oil, and vice versa. This is logical since an elastic supply curve implies that the quantity produced is highly sensitive to changes in price. In addition, the higher the elasticity of demand for crude oil, the higher the proportion of incremental oil sands production that would be expected to add to total global oil supply (61).

As previously stated, there is greater potential for incremental oil sands production at crude oil prices between USD 60 and 80/bbl. Global oil supply curve studies generally show a large amount of global oil production potential in this price range. 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 (62). 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 (63).

[xxviii] Global light oil includes Eagle Ford, North Sea Forties, Arab Light, Bakken Blend, Kirkuk, Basrah Light, Bonny Light, and Alaskan North Slope. Global heavy oil includes Venezuela Petro Zuata, Venezuela Boscan, Venezuela Bachaquero, Mexico Maya, North Sea Mariner, and Brazil Marlim.

With a considerable amount of potential global oil supply available at prices below USD 80/bbl, a large proportion of any incremental oil sands production would be expected to displace other types of crude oil production, rather than add to total global oil supply. Given the comparable WTT emissions noted above between different types of crude oil, it is likely that there would only be small net change in global GHG emissions based on the WTT difference. The total global GHG impact would be larger if a larger portion of incremental oil sands production were expected to add to total global oil supply and global demand were highly elastic[xxix].

Conclusion

In Part A of this review, ECCC presented estimates of the upstream GHG emissions in Canada associated with the production and processing of crude oil and refined products that could be transported by the expanded Trans Mountain pipeline system if the project is approved. Publicly-available data and established methodologies do not currently allow for the inclusion of indirect emissions such as those associated with land-use changes and grid electricity or fuels that are produced elsewhere. The projections for GHG emissions and production were modelled up to the year 2030 and include the estimated future impacts of existing policies and measures as of September 2015.

ECCC projects that the upstream GHG emissions in Canada resulting from the production, processing, and refining of products associated with the expanded nominal capacity of the TMPL system could range from 21 to 26 Mt of CO2 eq per year. Considering only the capacity added by the Project, emissions could range from 13 to 15 Mt of CO2 eq per year.

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

- *If the Project is the only pipeline capacity added from Western Canada,* there would be no incremental production and upstream emissions if the netback price for the marginal barrel of oil sands production was unaffected. This could occur because the amount of oil sands production already expected to be completed by 2019, as well as volumes currently transported by rail, are more than the additional capacity of the proposed project. However, increased pipeline network efficiency or changes in the marginal cost of transportation from Western Canada could result in incremental production and upstream emissions under this scenario.

- *If additional pipeline capacity, including the Project, is built such that shipping crude-by-rail was no longer needed*, a portion of the emissions calculated in Part A could be incremental.

[xxix] A range of demand elasticities are assumed in Erickson and Lazarus (2014) while demand elasticity sensitivities were examined by Navius Research in their analysis of the Energy East pipeline project.

- The extent of incremental production and emissions under either scenario depends on the long-term price of Canadian light oil.
    - At prices lower than USD 60/bbl, most planned oil sands projects not yet under construction would likely be unprofitable and would not be built, meaning there is unlikely to be incremental emissions.
    - At prices of USD 60-80/bbl, many potential projects could become profitable with pipeline access. However, the amount of incremental production that would come online is uncertain.
    - At prices 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 at a lower level than if oil prices were in the USD 60-80/bbl range noted above.

- If additional pipeline capacity resulted in incremental oil sands production, there could be an impact on global supply and prices. Incremental production would either displace other sources of crude oil at the margin, or add to total global supply. Where it displaces other types of crude oil, the impact on global emissions would be the difference in well-to-tank GHG emissions. Where it adds to total global oil supply, lower global prices and increases in the quantity of oil demanded would increase emissions based on the full well-to-wheels lifecycle emissions.

- Given that a substantial amount of global crude oil supply is financially viable in a similar crude oil price range to Canadian in situ oil sands, it is expected that a larger portion of incremental production would displace other types of crude oil.

Bibliography

1. **Government of Canada.** Interim Measures for Pipeline Reviews. *Government of Canada.* [Online] January 27, 2016. [Cited: November 15, 2016.] http://news.gc.ca/web/article-en.do?mthd=tp&crtr.page=1&nid=1029989&crtr.tp1D=930.

2. **IPCC [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)].** *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.* Geneva, Switzerland : IPCC, 2014.

3. **Lemmen, D.S., Warren, F.J., James, T.S. and Mercer Clarke, C.S.L. editors.** *Canada's Marine Coasts in a Changing Climate.* Ottawa, Ontario : Governement of Canada, 2016.

4. **Trans Mountain Pipeline ULC.** Service Standards Regarding the Transportation of Petroleum. *Kinder Morgan.* [Online] April 26, 2013. [Cited: November 15, 2016.] http://www.kindermorgan.com/content/docs/TM%20Service%20Standards%205.pdf.

5. **Government of Canada.** Trans Mountain Expansion Project. *Canadian Environmental Assessment Agency.* [Online] August 18, 2016. [Cited: November 15, 2016.] http://www.ceaa-acee.gc.ca/050/details-eng.cfm?evaluation=80061.

6. **Trans Mountain ULC.** Trans Mountain Response to NEB Information Request No. 1. *National Energy Board.* [Online] May 14, 2014. [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90552/548311/956726/2392873/2451003/2454322/B32-3_-_Trans_Mountain_Response_to_NEB_IR_No._1_2_of_2_-_A3W9H9.pdf?nodeid=2462074&vernum=-2. A3W9H9.

7. **Trans Mountain Pipeline ULC.** Trans Mountain Response to NEB IR No. 4. [Online] [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90552/548311/956726/2392873/2451003/2759257/B371-2_-_Trans_Mountain_Response_to_NEB_IR_No._4__-_A4K4W3_%28stricken_in_part%29.pdf?nodeid=2758991&vernum=-2.

8. **Rowan Williams Davies & Irwin Inc. (RWDI).** Supplemental Marine Air Quality and Greenhouse Gas Technical Report #2 and ESA Significance Ratings. *National Energy Board.* [Online] November 26, 2014. [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90552/548311/956726/2392873/2451003/2578063/B290%2D45_%2D_Part_3_Marine_AQ_Supp_Technical_Report_2_Pt01_%2D_A4F5H8.pdf?nodeid=2578729&vernum=-2.

9. **Government of Canada.** Canada's Second Biennial Report on Climate Change. *Environment and Climate Change Canada.* [Online] February 10, 2016. [Cited: November 15, 2016.] https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=02D095CB-1.

10. **National Energy Board.** Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040. *National Energy Board.* [Online] January 2016. [Cited: November 15, 2016.] https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html.

11. **Rowan Williams Davies & Irwin Inc. (RWDI).** Trans Mountain Expansion Project - Final Report - Supplemental Air Quality Technical Report For Technical Update No. 2 - SREP-NEB-TERA-00020 - RWDI # 1402013. *National Energy Board.* [Online] August 22, 2014. [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90552/548311/956726/2392873/2451003/2499084/B255-31_-_Part_3_Air_Quality_Assessment_Update_Westridge_Burnaby_-_A4A4E3.pdf?nodeid=2499085&vernum=-2.

12. **Muse Stancil & Co.** Market Prospects and Benefits Analysis of the Trans Mountain Expansion Project for Trans Mountain Pipeline (ULC). *National Energy Board.* [Online] September 2015. [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90552/548311/956726/2392873/2451003/2825642/B427%2D2_%2D_2a_Muse_Stancil%2C_Market_Prospects_and_Benefits_Analysis_of_the_TMEP%2C_September_2015_%2D_A4T6E8.pdf?nodeid=2825856&vernum=-2.

13. **IHS Inc.** *Comparing GHG Intensity of the Oil Sands and the Average U.S. Crude Oil.* s.l. : IHS Inc., 2014.

14. **Government of Alberta.** Climate Leadership Plan. *Government Projects, Priorities and Consultations.* [Online] [Cited: November 15, 2016.] http://www.alberta.ca/climate-leadership-plan.cfm.

15. **Government of British Columbia.** Climate Leadership Plan. *British Columbia.* [Online] [Cited: November 15, 2016.] http://climate.gov.bc.ca/feature/climate-leadership-plan/.

16. **First Ministers.** Vancouver Declaration on clean growth and climate change. *Canadian Intergovernmental Conference Secretariat.* [Online] March 3, 2016. [Cited: November 15, 2016.] http://www.scics.gc.ca/english/conferences.asp?a=viewdocument&id=2401.

17. **Government of Canada.** Pan-Canadian Approach to Pricing Carbon Pollution. *Backgrounder.* [Online] Environment and Climate Change Canada, 10 3, 2016. [Cited: November 15, 2016.] http://news.gc.ca/web/article-en.do?nid=1132169.

18. **National Energy Board.** *Canada's Energy Future 2016: Update - Energy Supply and Demand Projections to 2040.* 2016.

19. **International Energy Agency.** World Energy Outlook. *World Energy Outlook.* [Online] November 1, 2015. [Cited: November 15, 2016.] http://www.worldenergyoutlook.org/.

20. *U.S. Refineries – Stated Capacities as of January 1, 2016.* **Oil and Gas Journal.** 12, s.l. : Oil and Gas Journal, 2015, Vol. 113.

21. **National Energy Board.** *Estimated Canadian Crude Oil Exports by Type and Destination.* 2015.

22. **Canadian Association of Petroleum Producers.** 2016 CAPP Crude Oil Forecast, Markets & Transportation. *Publications.* [Online] June 2016. [Cited: November 15, 2016.] http://www.capp.ca/publications-and-statistics/crude-oil-forecast.

23. **Oil and Gas Journal.** 2016 Worldwide Refining Survey. [Online]

24. **U.S. Energy Information Administration.** Coking is a refinery process that produces 19% of finished petroleum product exports. *Today in Energy.* [Online] January 28, 2013. [Cited: November 15, 2016.] https://www.eia.gov/todayinenergy/detail.cfm?id=9731.

25. **Hackett, D., et al., et al.** Pacific Basin Heavy Oil Refining Capacity. *University of Calgary - The School of Public Policy.* [Online] February 2013. [Cited: November 15, 2016.] https://www.policyschool.ca/wp-content/uploads/2016/03/pacific-basin-hackett-noda-grissom-moore-winter.pdf.

26. **U.S. Energy Information Administration.** China - International energy data and analysis. *eia Beta.* [Online] May 14, 2015. [Cited: November 15, 2016.] http://www.eia.gov/beta/international/analysis.cfm?iso=CHN.

27. *A refined approach: Saudi Arabia moves beyond crude.* **Krane, J.** 82, s.l. : Energy Policy, 2015.

28. **Muse Stancil.** *Update of market Prospects and Benefits Analysis for the Northern Gateway Project for Enbridge.* s.l. : Muse Stancil, 2012.

29. **Wood Mackenzie.** *Saudi Arabia's crude dominance in Asia – A thing of the past?* s.l. : Wood Mackenzie, 2015.

30. **Organization of the Petroleum Exporting Countries.** 2015 World Oil Outlook. *Organization of the Petroleum Exporting Countries.* [Online] October 2015. [Cited: November 15, 2016.] http://www.opec.org/opec_web/static_files_project/media/downloads/publications/WOO%202015.pdf.

31. **Wu, K.** *Special Report: Capacity, Complexity Expansions Characterize China's Refining Industry Past, Present, Future.* s.l. : Oil & Gas Journal, 2011.

32. **Wood Mackenzie.** *Saudi Aramco IPO: Not priceless but peerless.* s.l. : Wood Mackenzie, 2016.

33. —. *Motiva: Shell and Saudi Aramco end refining JV.* s.l. : Wood Mackenzie, 2016.

34. **Ulmer and Ore.** 2015.

35. **U.S. Energy Information Administration.** Korea,South - International energy data and analysis. *eia Beta.* [Online] October 5, 2015. [Cited: November 15, 2016.] http://www.eia.gov/beta/international/analysis.cfm?iso=KOR.

36. —. California - State Profile and Energy Estimates. *Independent Statistics & Analysis.* [Online] September 17, 2015. [Cited: November 15, 2016.] http://www.eia.gov/state/analysis.cfm?sid=CA.

37. *U.S. Refineries - Stated Capacities as of january 1, 2016.* 12, s.l. : Oil and Gas journal, 2015, Vol. 113.

38. **Mulshof, Menno et. al.** Oil Sands Breakeven Prices Revisited. s.l. : TD Securities Inc., 2016.

39. **National Energy Board.** Market Snapshot: Oil Sands Production to Increase, but Effects of Low Prices are Evident. *National Energy Board.* [Online] Government of Canada, 12 15, 2015. [Cited: November 15, 2016.] https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2015/12-03lsndsprdctn-eng.html.

40. **Board, National Energy.** *Canada's Pipeline Transportation System 2016.* s.l. : Government of Canada, 2016.

41. *IHS Oil Sands Dialogue - Forces of Change.* **IHS Inc.** 2016.

42. *Un-burnable oil: an examination of oil resource utilisation in a decarbonised energy system.* **McGlade, C. and Ekins, P.** 64, s.l. : Energy Policy.

43. *The geographical distribution of fossil fuels unused when limiting global warming to 2C.* **McGlade, C. and Ekins, P.** 517, s.l. : Nature, 2015.

44. **International Energy Agency.** *World Energy Investment Outlook.* Paris : s.n., 2015.

45. **Bataille, C., Sawyer, D. and Melton, N.** *patways to deep decarbonization in Canada.* s.l. : Sustainable Develoipment Solutions Network (SDSN) and Institute for Sustainable Development and International Relations (IDDRI), 2015.

46. **Railway Association of Canada.** *Locomotive Emissions Monitoring Program 2012.* Ottawa : Railway Association of Canada. ISBN 978-1-927520-02-4.

47. **U.S. Energy Information Administration.** U.S. Movements of Crude Oil By Rail. *Independent Statistics & Analysis.* [Online] April 4, 2016. [Cited: November 15, 2016.] https://www.eia.gov/petroleum/transportation/.

48. **RBN Energy.** *Slow Train Coming: What's Ahead for Crude-by-rail.* 2016.

49. **U.S. Department of State.** Final Supplemental Environmental Impact Statement (SEIS). *Keystone XL Pipeline Project.* [Online] January 2014. [Cited: November 15, 2016.] https://keystonepipeline-xl.state.gov/finalseis/index.htm.

50. **National Energy Board.** Feature Article: Estimates of Canadian crude by rail movements show a peak in October 2015, roughly one quarter of total loading capacity. *National Energy Board.* [Online] February 25, 2016. [Cited: November 15, 2016.] https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/prcstrdrtcl/qrtrlprcpdts/ftrrtcl/2016-02-01cndncrdrl-eng.html.

51. **Fielden, S.** Slow Train Coming – Massive Over Capacity at Gulf Coast Crude-By-Rail Terminals. *RBN Energy LLC.* [Online] April 17, 2016. [Cited: November 15, 2016.] https://rbnenergy.com/slow-train-coming-massive-over-capacity-at-gulf-coast-crude-by-rail-terminals.

52. **RBN Energy LLC.** *Go Your Own Way: Moving Western Canadian Bitumen to Market.* s.l. : RBN Energy LLC, 2014.

53. **National Energy Board.** Application by Trans Mountain for Approval of the Transportation Service and Toll Methodology for the Expanded Trans Mountain Pipeline System - Direct Evidende of John J. Reed. [Online] June 29, 2012. [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/552980/954292/828580/865601/901928/B15-13_-_Revised_Jan_10_2013_TAB_E_1_-_J_Reed_TM_Testimony_-_A3E7C4_.pdf?nodeid=902005&vernum=-2.

54. —. Tab C - Transportation Service and Toll Methodology. [Online] [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/552980/954292/828580/865601/828070/B1-5_-_Tab_C_-_Toll_Structure_-_A2U4S7.pdf?nodeid=828253&vernum=-2.

55. **Trans Mountain Pipeline ULC.** B15 - Trans Mountain Pipeline ULC - Revised Trans Mountain Pipeline ULC Application Pursuant to Part IV of the NEB Act (A50046). *National Energy Board.* [Online] October 1, 2013. [Cited: November 15, 2016.] https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/552980/954292/828580/865601/901928/B15-5_-_Revised_Jan_10_2013_TAB_C_Toll_Structure_-_A3E7A6.pdf?nodeid=901932&vernum=-2.

56. **Millington, D. and Murillo, Carlos A.** *Canadian Oil Sands Supply Costs and Development Projects (2015-2035).* s.l. : Canadian Energy Research Institute (CERI), 2015.

57. **Navius Research Inc.** *A review of ECCC's method for estimating upstream GHGs.* 2016.

58. —. *Greenhouse Gas Emissions Resulting from the Energy East Pipeline Project.* s.l. : Ontario Energy Board, 2014.

59. **IHS CERA.** *Keystone XL Pipeline: No Material Impact on US GHG Emissions.* 2013.

60. **Navius Research.** *Discussion Paper: Greenhouse Gas Emissions Resulting from the Energy East Pipeline Project.* 2015.

61. *Impact of the Keystone XL Pipeline on Global Oil Markets and Greenhouse Gas Emissions.* **Erickson, Peter and Lazarus, Michael.** s.l. : Nature Climate Change, 2014, Vol. 4, pp. 778-781.

62. **Wood Mackenzie.** *Pre-FID Oil Projects: Global Breakeven Analysis and Cost Curves.* s.l. : Wood Mackenzie, 2016.

63. **Goldman Sachs.** *420 Projects to Change the World.* s.l. : Goldman Sachs, 2015.

64. *Oil Sands Shaken, Not Stirred: First material cancellation of in-flight project unlikely to be harbinger of things to come.* s.l. : IHS Inc., 2015.

65. **CanOils.** Oil Sands Project Status. [Online] Evaluate Energy. [Cited: November 15, 2016.] www.canoils.com.

66. **North Dakota Pipeline Authority.** Data/Statistics. [Online] ND Pipeline Authority, 2013. [Cited: November 15, 2016.] https://northdakotapipelines.com/datastatistics.

67. **Enbridge Energy.** Reports & Filings. [Online] Enbridge, 2015. [Cited: November 15, 2016.] http://www.enbridge.com/investment-center.

Annex A – Proportions of Product Categories for the Future Mix

Scenario 1

Line 1

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	42.2	-	-	-	-	47.5	10.3
2020	39.8	-	-	-	-	49.3	10.9
2021	37.1	-	-	-	-	52.5	10.5
2022	36.5	-	-	-	-	53.1	10.4
2023	35.1	-	-	-	-	54.7	10.2
2024	32.5	-	-	-	-	58.1	9.5
2025	29.9	-	-	-	-	61.6	8.5
2026	28.4	-	-	-	-	62.4	9.2
2027	30.0	-	-	-	-	59.5	10.5
2028	32.7	-	-	-	-	57.3	10.0
2029	28.7	-	-	-	-	60.7	10.6
2030	28.5	-	-	-	-	60.7	10.7

Line 2

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	6.2	1.7	21.7	53.0	9.1	6.9	1.5
2020	3.9	1.3	16.7	61.5	10.6	4.9	1.1
2021	4.8	0.7	9.3	65.6	11.5	6.8	1.4
2022	5.1	0.2	3.0	70.5	12.4	7.4	1.4
2023	5.3	0.2	3.1	69.3	12.2	8.3	1.5
2024	6.9	0.1	1.0	66.0	11.6	12.3	2.0
2025	9.4	0.1	1.0	57.3	10.1	19.4	2.7
2026	6.7	0.1	1.1	63.9	11.3	14.8	2.2
2027	3.9	0.1	1.3	72.8	12.8	7.8	1.4
2028	5.5	0.1	1.1	69.7	12.3	9.7	1.7
2029	3.5	0.1	1.1	73.8	13.0	7.3	1.3
2030	3.2	0.1	1.0	74.7	13.2	6.7	1.2

Scenario 2

Line 1

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	42.8	-	-	-	-	44.6	12.6
2020	42.7	-	-	-	-	44.8	12.6
2021	42.7	-	-	-	-	44.8	12.6
2022	42.7	-	-	-	-	44.7	12.6
2023	42.8	-	-	-	-	44.6	12.6
2024	42.8	-	-	-	-	44.6	12.6
2025	43.0	-	-	-	-	44.4	12.6
2026	43.3	-	-	-	-	44.1	12.6
2027	43.4	-	-	-	-	44.0	12.6
2028	43.5	-	-	-	-	43.9	12.6
2029	43.6	-	-	-	-	43.8	12.6
2030	43.7	-	-	-	-	43.7	12.6

Line 2

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	-	30.7	13.3	38.6	17.3	-	-
2020	-	29.9	13.2	39.9	16.9	-	-
2021	-	29.2	13.2	41.1	16.5	-	-
2022	-	28.2	13.1	42.3	16.4	-	-
2023	-	26.8	12.9	43.8	16.5	-	-
2024	-	25.9	12.8	45.0	16.3	-	-
2025	-	23.2	12.8	46.3	17.7	-	-
2026	-	22.6	12.8	47.3	17.3	-	-
2027	-	22.2	12.8	48.2	16.8	-	-
2028	-	21.8	12.8	49.1	16.4	-	-
2029	-	21.4	12.7	49.9	16.0	-	-
2030	-	21.0	12.7	50.6	15.6	-	-

Scenario 3

Line 1

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	20.2	-	-	-	-	67.2	12.6
2020	20.2	-	-	-	-	67.2	12.6
2021	20.2	-	-	-	-	67.2	12.6
2022	20.2	-	-	-	-	67.2	12.6
2023	20.2	-	-	-	-	67.2	12.6
2024	20.2	-	-	-	-	67.2	12.6
2025	20.2	-	-	-	-	67.2	12.6
2026	20.2	-	-	-	-	67.2	12.6
2027	20.2	-	-	-	-	67.2	12.6
2028	20.2	-	-	-	-	67.2	12.6
2029	20.2	-	-	-	-	67.2	12.6
2030	20.2	-	-	-	-	67.2	12.6

Line 2

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	-	30.7	13.3	38.6	17.3	-	-
2020	-	29.9	13.2	39.9	16.9	-	-
2021	-	29.2	13.2	41.1	16.5	-	-
2022	-	28.2	13.1	42.3	16.4	-	-
2023	-	26.8	12.9	43.8	16.5	-	-
2024	-	25.9	12.8	45.0	16.3	-	-
2025	-	23.2	12.8	46.3	17.7	-	-
2026	-	22.6	12.8	47.3	17.3	-	-
2027	-	22.2	12.8	48.2	16.8	-	-
2028	-	21.8	12.8	49.1	16.4	-	-
2029	-	21.4	12.7	49.9	16.0	-	-
2030	-	21.0	12.7	50.6	15.6	-	-

Scenario 4

Line 1

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	87.4	-	-	-	-	-	12.6
2020	87.4	-	-	-	-	-	12.6
2021	87.4	-	-	-	-	-	12.6
2022	87.4	-	-	-	-	-	12.6
2023	87.4	-	-	-	-	-	12.6
2024	87.4	-	-	-	-	-	12.6
2025	87.4	-	-	-	-	-	12.6
2026	87.4	-	-	-	-	-	12.6
2027	87.4	-	-	-	-	-	12.6
2028	87.4	-	-	-	-	-	12.6
2029	87.4	-	-	-	-	-	12.6
2030	87.4	-	-	-	-	-	12.6

Line 2

Year	Conv. Light (%)	Conv. Heavy (%)	CSS Heavy (%)	SAGD Heavy (%)	Mined Bitumen (%)	Synthetic Crude (%)	Refined Products (%)
2019	-	30.7	13.3	38.6	17.3	-	-
2020	-	29.9	13.2	39.9	16.9	-	-
2021	-	29.2	13.2	41.1	16.5	-	-
2022	-	28.2	13.1	42.3	16.4	-	-
2023	-	26.8	12.9	43.8	16.5	-	-
2024	-	25.9	12.8	45.0	16.3	-	-
2025	-	23.2	12.8	46.3	17.7	-	-
2026	-	22.6	12.8	47.3	17.3	-	-
2027	-	22.2	12.8	48.2	16.8	-	-
2028	-	21.8	12.8	49.1	16.4	-	-
2029	-	21.4	12.7	49.9	16.0	-	-
2030	-	21.0	12.7	50.6	15.6	-	-

Annex B –Emission Factors Methodology

Emission factors were developed for categories of crude oil expected to be transported by the TMPL system, including crude oil produced from different production and processing operations, diluents that assist the movement of heavier crude oil, and refined petroleum products. The emission factors reflect changes in the emission intensity of the activities associated with the extraction and processing of crude oil over time. The emission factors take into account all on-site sources of emissions associated with production and processing including combustion, flaring, venting, and fugitive.

General Approach to Crude Oil Emission Factors

ECCC has developed emission projections for future years for the different crude oil categories. These are presented in *Canada's Second Biennial Report on Climate Change* (9) for the period to 2030. The level of emissions associated with each crude oil category is a function of:

1. The extent of the production activity, and
2. The expected changes to the emission intensity associated with that crude oil category.

The expected future demand and resulting production activity for the crude oil categories comes from the NEB's *with current measures* reference scenario (10). The expected changes over time to the emission intensity of the activities associated with the extraction and processing of crude oil are a function of environmental policy and technology implementation. The emissions and production projections used by Environment and Climate Change Canada for this review include the estimated future impacts of existing policies and measures that have been implemented as of September 2015. Projections of emissions estimates for onshore conventional light and heavy crude oil, oil sands production by cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD), and mined bitumen were used. The projections also include assumptions around energy efficiency and other improvements at oil and gas facilities. The combination of the emissions and production projections allows for the calculation of unique annual emission intensities associated with the extraction and processing of different categories of crude oil to 2030.

Synthetic Crude Oil Emission Factor

Synthetic crude oil (SCO) is an intermediate product that is obtained from heavy crude oil produced by conventional means, CSS, SAGD, and mined bitumen production methods. Each production method has a unique range of emission intensities representing the particular technology and operations to produce a barrel of oil. The process of producing SCO is called *upgrading*. The SCO emission factor used in the estimates of upstream emissions associated with the Project takes into account the emissions associated with both the production of heavy crude oil or bitumen to be upgraded, and the emissions associated with the upgrading activity itself. The calculation of the SCO emission factor for a given year requires a two-step process, which is outlined below.

Only portions of the crude oil produced in Canada is upgraded domestically. Based on historical records, most of the mined bitumen is upgraded in Canada while only smaller portions of heavy crude oil produced by CSS, SAGD, and conventional methods is upgraded in Canada. The NEB provides projected amounts of heavy crude oil produced by conventional methods, mined bitumen, and *in situ* oil sands production that are upgraded domestically in future years (10). The *in situ* oil sands production includes production using CSS and SAGD methods, where 25% of the volume was allocated to CSS and the remaining 75% to SAGD. To calculate an emission factor, the emission intensities corresponding to each crude oil category were multiplied by the proportional contribution of that category to the total volume upgraded. The proportion of upgraded crude oil in each category was determined by dividing the volume of upgraded crude oil in that category by the total volume upgraded. The following equation shows the calculation for the emission factor, in units of emissions per barrel.

$$\mathrm{EF}_{Upgrader\ Feed} = \sum_i \left(P_i * \mathrm{EI}_i\right)$$

Where,

i is the crude oil category,

P_i is the volume of the crude oil in category i that is upgraded divided by the total volume of all crude oil categories that is updgraded

EI_i is the emission intensity for the production of crude oil in category i

Based on discussion with the NEB, the production of a barrel of SCO requires, on average, upgrading 1.1 barrels of crude oil. To convert the emission factor for upgrader feed from units of emissions per barrel of crude oil product into units of emissions per barrel of SCO, the emission factor ($\mathrm{EF}_{Upgrader\ Feed}$) was adjusted by multiplying it by 1.1.

To determine the emission factors associated with the activity of upgrading, the emissions resulting from upgrading were divided by the amount of SCO produced. The emissions associated with upgrading were obtained from the underlying data of *Canada's Second Biennial Report on Climate Change* (9), and the production of SCO was obtained from the NEB (10).

The overall emission factor for the production of SCO is the sum of the emission factor ($\mathrm{EF}_{Upgrader\ Feed}$) and the emission factor associated with upgrading ($\mathrm{EF}_{Upgrading}$), as outlined in the equation below:

$$\mathrm{EF}_{SCO} = \mathrm{EF}_{Upgrading} + \mathrm{EF}_{Upgrader\ Feed} * 1.1$$

Emission Factors Determined Using Facilities Reported Data

Emission factors associated with the production of crude oil (including SCO) by CSS, SAGD, and bitumen mining methods can also be determined using facility-reported emissions and production data. Large oil production and processing facilities exceed provincial and federal thresholds for annual GHG emissions reporting. The reporting requirements of the federal *Greenhouse Gas Reporting Program* (GHGRP) and provincial reporting regimes such as the *Specified Gas Emitters Regulation* (SGER) in Alberta capture the majority of the emissions from the aforementioned production methods for those crude oil categories. The level of production from each facility was obtained from provincial reporting sources (e.g Statistical Reports ST 53 and ST 39 from the Alberta Energy Regulator).

Facility-level emissions and production are available for historic years up to and including 2014. The type of production operations occurring at a facility is usually reported. Some facilities produce a single product, while others produce SCO in addition to non-upgraded crude oil. Facilities producing upgraded as well as non-upgraded crude oil are called *integrated facilities*. They can upgrade products from their own production or from other facilities to produce SCO. In integrated facilities, the emissions associated with the non-upgraded production are difficult to segregate from the emissions associated with the production of SCO. ECCC has developed a method to segregate the emissions associated with the production of non-upgraded products and with the upgrading activities for each integrated facility in Canada. In general, ECCC has assumed a 40% share of emission from mining activities and a 60% share for upgrading activities at an integrated facility (based on the natural gas requirements of separate mining and upgrading activities from CERI Study No. 119, Part II – Oil Sands Supply Cost and Production). These proportions, however, are subject to the fuel use constraints imposed by Statistics Canada Report on Energy Supply and Demand and Canada's GHG Inventory. Using these proportions the total emissions from integrated facilities were disaggregated into crude oil production and upgrading emissions.

The 2014 emission factors for each crude oil category and for the upgrading activity was determined by aggregating emissions from facilities producing similar crude oils and dividing this by their aggregated production, as per the following equation:

$$\mathrm{EF(facil)}_{i,2014} = \frac{\sum_{j=1}^{n} Emissions_j}{\sum_{j=1}^{n} Production_j}$$

Where,

i is the crude oil category (CSS, SAGD, mined bitumen, and SCO),

j is a facility with i^{th} production or upgrading activity,

n is total number of facilities with i^{th} production or upgrading activity, and

$\mathrm{EF(facil)}_{i,2014}$ is the emission factor representing i^{th} product or upgrading activity for the year 2014.

Estimates of emission factors for future years were calculated based on the changes projected for the emission factors using data from *Canada's Second Biennial Report on Climate Change* (9) and the NEB report *Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2040* (10). Information regarding changes in emissions intensities for future years were obtained from the calculated emission factors for projected years determined in the *General Approach to Crude Oil Emission Factors* section of this Annex. Similarly, the projected changes in the upgrading emission factor were obtained from following the approach in the *Synthetic Crude Oil Emission Factor* section. The proportion of change in the projected emission factors was determined by dividing the emission factor for a given projected year by the emission factor for the year 2014, as per the following equation.

$$\mathrm{PC}_{i,t} = \frac{\mathrm{EF}_{i,t}}{\mathrm{EF}_{i,2014}}$$

Where,

i is the crude oil category (CSS, SAGD, mined bitumen, and SCO),

t is an applicable projected year,

EF is the emission factor as determined by the methodology in the *General Approach to Crude Oil Emission Factors* and *Synthetic Crude Oil Emission Factor*, and
PC is the proportion of change in the projected emission factor.

The 2014 emission factors determined from the facility-reported data were then multiplied by the proportion of change for the applicable projected years in order to develop projected emission factors that are based on facilities reported data.

$$\mathrm{EF(facil)}_{i,t} = \mathrm{PC}_{i,t} * \mathrm{EF(facil)}_{i,2014}$$

Where,
i is the product type of CSS, SAGD, mined bitumen, and SCO,
t is an applicable projected year,
PC is the proportion of change in the projected emission factor, and
EF(facil) is the emission factor developed based on facility reported data.

Diluent Production Emission Factors

Heavier crude oil requires that it be blended with diluent to facilitate its movement through a pipeline. The type of and quantity of heavy crude oil being transported will impact the quantity of diluent required. The proportion of diluent needed for blending varies for different categories of heavy crude oil. The following table provides the volume proportions of diluent needed.

Crude Oil Category	Diluent Proportion
Conventional Heavy	8%
CSS Heavy	30%
SAGD Heavy	30%
Mined Bitumen	20%

The volume of diluent production projection is obtained from the NEB's *with current measures* reference scenario (10). The pentanes plus production projections provide the volumes of diluent expected to be produced and imported. Most of the diluent demand in Canada is fulfilled by imports[xxx]. The Canadian production comes from field condensate production, condensate production at gas processing facilities, and production from refineries. Field condensate production is the largest portion of domestic production, followed by condensate production at gas processing facilities, small volumes of production from refinery operations. Only domestic production of field condensate and condensate production at gas processing facilities are considered when calculating emissions because these operations result in the condensate being the significant product or co-products.

The emission factors for conventional light crude oil were used to determine the emissions from the production of condensate. The volume of condensate produced domestically and resulting from field

[xxx] According to NEB, net imports of diluent grow from 58% of the total diluent demand in 2020, to 72% of the total diluent demand in 2030, to 77% of the total diluent demand in 2040.

production and gas processing operations is multiplied by the emission factor to determine the upstream emissions associated with the diluent.

Refined Petroleum Products Production Emission Factors

Other hydrocarbon products that can be transported by pipeline include refined petroleum products (RPP). They are produced in refining operations and include gasoline, diesel, and other products. The upstream GHG emissions associated with the production of RPP include the emissions associated with refining operations and with the production of feedstock (e.g. crude oil). Emission factors are determined for both sources of emissions, and are added together to result in an overall emission factor representing upstream GHG emissions from RPP.

For each projection year, the emission factor for RPP production is determined by dividing the projected emissions from refinery operations by the projected RPP production, as per the following equation:

$$\mathrm{EF}_{RPP-prod} = \frac{\mathrm{RPP}_{Emission}}{\mathrm{RPP}_{Production}}$$

Where,

$\mathrm{RPP}_{Emission}$ is the total GHG emissions from refining operations,
$\mathrm{RPP}_{Production}$ is the annual quantity of RPP production, and
$\mathrm{EF}_{RPP-prod}$ is the emission factor representing refining operation

The projected emissions from the production of RPP is obtained from *Canada's Second Biennial Report on Climate Change* (9).

The emission factor associated with the feedstock used in the production of RPP is determined by proportionally taking into account the emissions intensities associated with the production of different types of crudes oils. Feedstock may consist of conventional crude oil and oil sands-derived crude oil. The historic proportions of crude oil representing the feedstock were used to determine the projection years' feedstock proportions. The projection year's feedstock proportions were then used to adjust the emission factors of the specific crude oils to calculate the overall emission factor, which represents the emissions associated with producing refinery feedstock, as per the following equation:

$$\mathrm{EF}_{RPP-feed} = \sum_j \left(\mathrm{EF}_{feed\ crude,j} * P_{feed\ crude,j}\right)$$

Where,

j is the individual crude oil making up the feedstock for refining,
$\mathrm{EF}_{feed\ crude,j}$ is the production emission factor of crude oil *j*,
$P_{feed\ crude,j}$ is the proportion of crude oil *j* forming the feedstock, and
$\mathrm{EF}_{RPP-feed}$ is the emission factor representing emissions from refinery feedstock production

The proportions of crude oil making up the feedstock were obtained from IHS inc. The overall emission factor for the production of RPP is the sum of the emission factor for the production of RPP and the RPP feedstock emission factor multiplied by the refinery feed to production ratio. This is represented by the following equation:

$$\mathrm{EF}_{RPP} = \mathrm{EF}_{RPP-prod} + \mathrm{EF}_{RPP-feed} * R$$

Where,

R is the ratio of refinery feed to refinery production, this is determined by dividing the total refinery feed volume by refinery production volume

EF_{RPP} is the emission factor for RPP products

Annex C – Limitations of the Analysis

There are a number of limitations to scope for the estimation of upstream GHG emissions in Part A. These include:

- Part A estimates do not include estimates of emissions from land use change related to upstream oil and gas activities. For land use change, ECCC uses country-specific methodologies that are consistent with Intergovernmental Panel on Climate Change (IPCC) guidelines to estimate emissions from certain land-use change categories (e.g. forest conversion) for Canada's national GHG inventory and *Canada's Biennial Report on Climate Change* (9). Estimating emissions from land-use change in the context of upstream GHG assessments for energy projects requires development of additional methodologies and emission factors, in particular for the conversion of wetlands, which may be significant in some regions.
- In general, Part A estimates do not include GHG emissions generated during the production of purchased fuel and electricity used at upstream oil and gas facilities. While the emissions from the use of fuels, such as the diesel fuel used in oil sands mining trucks, are captured in this review, emissions from the production of that diesel fuel are not captured. To date it has not been possible to locate sufficient publicly-available fuel consumption data for upstream oil and gas production that would allow for the estimation of the emissions associated with the production, processing and transportation of purchased fuels and electricity at upstream oil and gas activities.
- Part A estimates do not include emissions related to the transportation of crude oil and refined products from facilities to the TMPL system. These are expected to be minor when compared to other upstream emission sources associated with the Project.

ECCC recognizes that there are GHG emissions related to land use change and the production, processing and transportation of fuels and electricity purchased by upstream oil and gas activities. ECCC continues to investigate potential data sources and methodologies to support the estimation of GHG emissions related to these emissions sources for future assessments. As GHG estimation methodologies and data limitations are addressed, they will be incorporated into upstream GHG assessments.

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

Annex D – 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	10,000	10,000	2016
In Situ	Sunshine Oil Sands	West Ells	Construction	5,000	7,100	2016
Mining	Canadian Natural Resources	Horizon Phase 2/3	Construction	125,000	125,000	2017
Mining	Suncor/Total/Teck	Fort Hills Phase 1	Construction	180,000	225,000	2017
In Situ	Harvest Operations Corp	BlackGold Phase 1	Steaming delayed[xxxii]	10,000	14,300	2018
Total under construction or expected				**479,500**	**588,800**	

Source: IHS (64); CanOils (65); Company Reports
Numbers may not add due to rounding

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