Public Interest Evaluation of the Trans Mountain Expansion Project

By

Thomas Gunton (PhD)

Sean Broadbent (PhD)

Marvin Shaffer (PhD)

Chris Joseph (PhD)

James Hoffele (MRM)

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School of Resource and Environmental Management

Simon Fraser University

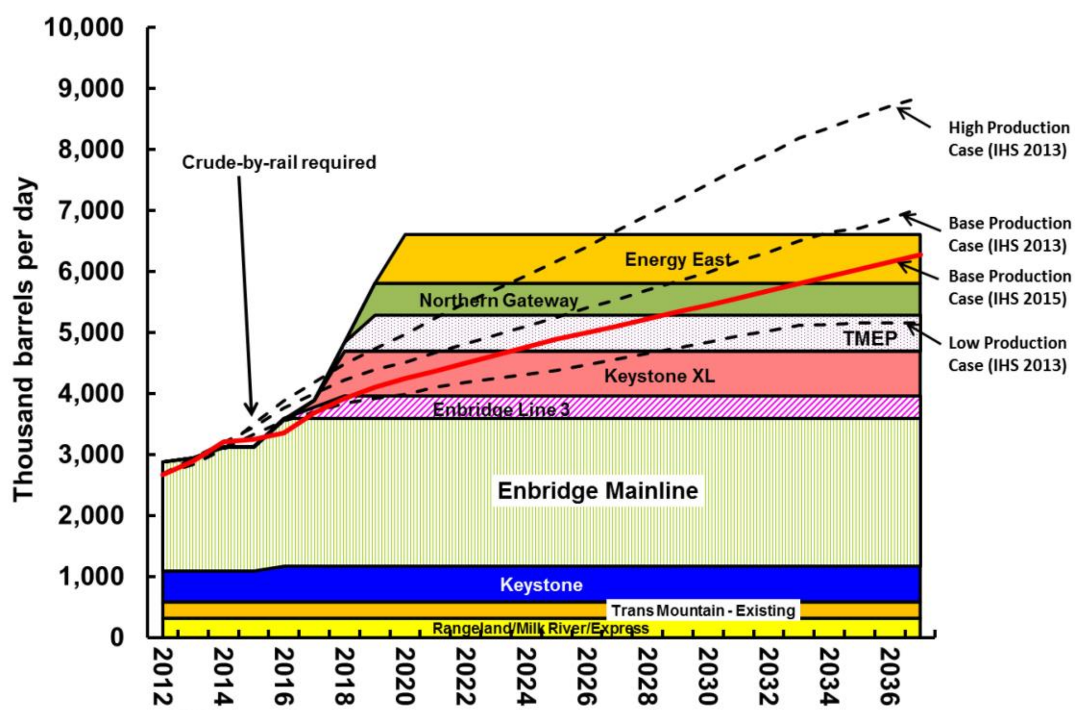
Executive Summary

1. The purpose of this report is to assess whether the proposed Trans Mountain Expansion Project (TMEP) is required and in the public interest.
2. The TMEP is a proposal to expand the existing Trans Mountain Pipeline (TMPL) to provide an additional 590 kbpd transportation capacity to ship crude oil from Alberta to markets in the Pacific Rim. The TMEP would consist of twinned pipelines (one new and one existing), a marine terminal, and tanker traffic to ship oil from Vancouver to Pacific Rim markets.
3. The National Energy Board (NEB) approval criteria as specified in Section 52 of the *National Energy Board Act* require the applicant to show that:
   a) the project is required; and
   b) the project is in the public interest.
4. The TMEP application asserts that the TMEP is required and in the public interest for the following reasons:
   a) growth in production from the Western Canada Sedimentary Basin (WCSB) requires increased oil transportation capacity;
   b) TMEP will provide access to new markets in Asia and the United States;
   c) TMEP will increase netbacks to all Western Canadian oil producers by lowering transportation costs and accessing higher price markets; and
   d) construction and operation of the TMEP will stimulate economic activity in Canada and generate tax revenue for government.
5. The evidence in the TMEP application that the TMEP is required and in the public interest is incomplete and deficient in the following respects:
   a) TM's assessment uses gross economic impacts as the primary measure of the contribution of the project to the public interest instead of net impacts and net economic benefits;
   b) TM incorrectly assumes that economic impacts are a measure of benefits without taking into account the opportunity cost of the labour, capital and other resources it uses;
   c) TM overstates the need for the TMEP by underestimating current and potential WCSB transportation capacity and relying on optimistic oil price forecasts;
   d) TM overstates project benefits in its estimates of the impact of the TMEP on oil netbacks to producers;
   e) TM understates costs by not estimating the economic losses resulting from the excess transportation capacity TMEP will cause; omitting cost estimates of environmental impacts and risks TMEP entails; and not evaluating other adverse consequences that should be taken into account in a full and proper public interest benefit cost analysis of the project.
   f) TM fails to provide any benefit cost analysis undertaken in accordance with

well-established principles and guidelines, and does not set out in a clear and comprehensive way the advantages, disadvantages, and trade-offs of its proposed project as is necessary for determining whether the TMEP is in the public interest.

6. TM's analysis shows that construction of the TMEP will contribute to a large increase in surplus capacity in the oil transportation sector. TM estimates in its original application that there will be 1.8 million bpd of surplus capacity by 2019 if all proposed transportation projects proceed as planned. Based on TM's updated forecast (TM 2015a), surplus capacity is now estimated to be approximately 2.5 million bpd in 2019. TM's updated base case forecast shows that if all proposed projects proceed as planned there will be surplus pipeline capacity beyond 2037 (Figure 1). Surplus capacity may be even higher than TM's forecast because TM excludes rail transportation in its estimates. This unused capacity would impose a large cost on Canada's oil transportation sector, oil producers and the Canadian public in the form of reduced tax revenues. TM has not included the costs of this unused capacity in its evaluation of TMEP costs and benefits.

Figure 1. TM/IHS Estimates of Western Canadian Supply for Pipeline Export vs. Pipeline Capacity



Source: TM (2015a, p. 8).

7. To assess the need for and the impact of the TMEP on the public interest we have completed a comprehensive benefit cost analysis of the TMEP. We have assessed

the benefits and costs by key sector and stakeholder group and tested a range of scenarios and assumptions in our analysis to address uncertainty in project parameters and impacts. Our benefit cost analysis shows that:

a) Under base case assumptions the TMEP results in a **net cost** to Canada of $6.5 billion.

b) to address uncertainty in estimating benefits and costs of the TMEP we completed a large number of sensitivity analyses to test the impact of alternative assumptions. Under all scenarios tested, our analysis shows that the TMEP will result in a **net cost** to Canada that ranges between $4.1 and $22.1 billion. Fewer new projects and higher oil production reduce the net costs while more projects, lower oil production, and higher environmental impacts increase the net costs.

While we recognize that estimating benefits and costs of the TMEP is challenging and subject to many uncertainties, we believe that our results indicate clearly that the TMEP will impose significant net costs on Canadians. Further, our base case estimate of a cost of $6.5 billion is conservative because it omits many potential environmental and social costs which are difficult to quantify and are therefore not included in our cost estimates.

Table 1. Benefit Cost Analysis Results for TMEP

Item	Net Benefit (Cost), Base Case (million $)	Sensitivity Analysis Range (million $)[1]
TMEP Pipeline Operations	0	(792) to 396
Unused Oil Transportation Capacity	(3,098)	(13,338) to (2,112)
Oil Price Netback Increase	0	0 to 2,008
Employment	77	77 to 284
Tax Revenue	242	242-892
Electricity	(257)	No sensitivity
GHG Emissions from Construction and Operation of TMEP and marine traffic in defined study area	(289)	(916) to (289)
Other Air Emissions	(85)	(427) to (9)
Oil Spills	(1,022)	(1,022) to (310)
Passive Use Damages from Oil Spill	(2,026)	(17,667) to (2,026)

Item	Net Benefit (Cost), Base Case (million $)	Sensitivity Analysis Range (million $)[1]
Other Socio Economic, Environmental Costs not estimated	See Appendix A	
Base Case Net Cost	**(6,458)**	**(4,070) to (22,099)**

Note. 1. Based on sensitivity scenarios

8. One of the primary reasons that the TMEP will result in a large net cost to Canada is because TMEP will create excess pipeline capacity. There are currently more WCSB oil transportation projects planned than required, and construction of all proposed projects will result in a significant net cost to Canada. These pipeline projects were proposed before the current downturn in the oil markets and were able to secure long-term shipping contracts that may allow these projects to be built while externalizing the cost of the surplus capacity onto existing transportation systems, oil producers, and governments. The creation of this excess capacity can be prevented by rejecting or deferring new projects that are not required and developing a comprehensive oil transportation strategy that comparatively evaluates all proposed projects from a social, economic, and environmental perspective to determine which project or mix of projects are required and best meet Canada's needs.
9. A further reason that the TMEP will result in a net cost to Canada is due to the major environmental risks it entails, including the risk of marine oil spills in British Columbia. The marine spill risk can be avoided by relying on other transportation options that do not require oil tankers to ship oil to markets through Canadian waters.
10. In summary, our evaluation shows that:
    a) the TMEP application fails to show that the TMEP meets the need and public interest criteria required for NEB approval; and
    b) the TMEP will result in a significant net cost to Canada if the project is built and consequently the TMEP is not needed and is not in Canada's public interest.

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BC	British Columbia
BCA	benefit cost analysis
Bpd	barrels per day
CAPP	Canadian Association of Petroleum Producers
CERI	Canadian Energy Research Institute
EconIA	economic impact analysis
ENGP	Enbridge Northern Gateway Project
EVOS	*Exxon Valdez* oil spill
GDP	gross domestic product
GHG	greenhouse gas
GWh	gigawatt hour
IEA	International Energy Association
IHS	IHS Global Canada Limited
IOPCF	International Oil Pollution Compensation Fund
IR	information request
Kbpd	thousand barrels per day
LNG	liquefied natural gas
mbpd	million barrels per day
MWh	megawatt hour
NEB	National Energy Board
NEBA	*National Energy Board Act*
PHRCC	Petroleum Human Resources Council of Canada
TM	Trans Mountain
TMEP	Trans Mountain Expansion Project
TMPL	Trans Mountain Pipeline
TVAUs	tank Vapour Activation Units
US EIA	US Energy Information Administration
USGC	United States Gulf Coast
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate
WTA	willingness to accept
WTP	willingness to pay

1. Introduction

The purpose of this report is to assess:

- the costs and benefits of the Trans Mountain Expansion Project (TMEP); and
- whether TMEP meets the criteria for project approval for pipelines as set out in the *National Energy Board Act (NEBA)* including whether the TMEP is in the Canadian public interest.

Our conclusions show that:

- the evidence provided by Trans Mountain (TM) in their application to justify the TMEP has significant deficiencies and does not provide the information on project need, benefits, and costs required to assess whether the project is in the Canadian public interest and justify project approval; and
- if built as planned the TMEP will result in a significant net cost to Canada.

We begin this report with a review of the approval criteria in the *NEBA*. This is followed by a description of the TMEP and then an evaluation of the evidence provided in the TMEP application regarding the need for, and public interest benefits, of the TMEP. We then provide additional evidence in the form of a benefit cost analysis to assess the TMEP and determine if the TMEP meets the approval criteria as specified in the *NEBA*.

1.1. National Energy Board Approval Criteria

Section 52 of the *NEBA* states that the National Energy Board (NEB) will make a recommendation to the Minister on project applications and in making its recommendation it may have regard to the following factors:

a) the availability of oil, gas or any other commodity to the pipeline;
b) the existence of markets, actual or potential;
c) the economic feasibility of the pipeline;
d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and
e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.

The NEB defines the public interest as follows:

The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that change as society's values and preferences evolve over time. The Board estimates the overall public good a project may create and its potential negative aspects, weighs its various impacts, and makes a decision (NEB 2010a).

In addition to these general criteria, the NEB (2013d) has approved the following list of issues to be considered in the TMEP application:

- the need for the proposed project;
- the economic feasibility of the proposed project;
- the potential commercial impacts of the proposed project;
- the potential environmental and socio-economic effects of the proposed project, including any cumulative environmental effects that are likely to result from the project, including those required to be considered by the NEB's *Filing Manual* (NEB 2013c);
- the potential environmental and socio-economic effects of marine shipping activities that would result from the proposed Project, including the potential effects of accidents or malfunctions that may occur;
- the appropriateness of the general route and land requirements for the proposed project;
- the suitability of the design of the proposed project;
- the terms and conditions to be included in any approval the Board may issue;
- potential impacts of the project on Aboriginal interests;
- potential impacts of the project on landowners and land use;
- contingency planning for spills, accidents or malfunctions, during construction and operation of the project; and
- safety and security during construction of the proposed project and operation of the project, including emergency response planning and third-party damage prevention.

The NEB (2013d) states that it does not intend to consider the environmental and socio-economic effects associated with upstream activities, the development of oil sands, or the downstream use of the oil transported by the pipeline. Factors such as greenhouse gas (GHG) emissions from oil production, therefore, are excluded by the NEB in its consideration of the TMEP.

1.2. Certificate of Duty

This report has been prepared in accordance with our duty as experts to assist: (i) Tsawout First Nation, Upper Nicola Band and Living Oceans Society in conducting their assessment of the Project; (ii) provincial or federal authorities with powers, duties or functions in relation to an assessment of the environmental and socio-economic effects of the Project; and (iii) any court seized with an action, judicial review, appeal, or any other matter in relation to the Project. A signed copy of our Certificate of Expert's Duty is attached as Appendix "B". Attached as Appendix "C" are our respective curriculum vitaes.

2. Overview of the Trans Mountain Expansion Project

The TMEP is a proposal to expand the existing Trans Mountain Pipeline (TMPL) which has been operating since 1953. According to TM, the purpose of the TMEP is “to provide additional transportation capacity for crude oil from Alberta to markets in the Pacific Rim including BC [*British Columbia*], Washington State, California, and Asia” (TM 2013b, Vol. 1, p. 1-4). The TMEP would consist of twinned pipelines, a marine terminal, and tanker traffic to meet the project’s stated objective.

2.1. Key Project Components

2.1.1. Pipeline

The proposed TMEP would twin the existing TMPL from Edmonton, Alberta to the Westridge Marine Terminal in Burnaby, British Columbia (BC) and increase operating capacity from the current 300 thousand barrels per day (kbpd) of oil to 890 kbpd (TM 2013b, Vol. 2, p. 2-12). The TMEP would consist of two pipelines. The first line (Line 1) is a 1,147-km pipeline with the capability of transporting 350 kbpd (TM 2013b, Vol. 4A p. 4A-2-3). Line 1 would use mostly existing and reactivated TMPL pipeline to transport refined products and light crude oils but will also have the capability to carry heavy crude oil at a reduced throughput rate (TM 2013b, Vol. 4A p. 4A-2-3). Line 2 is a 1,180 km pipeline with throughput capacity of 540 kbpd for heavy crude oils but will also be capable of transporting light crude oils (TM 2013b, Vol. 4A p. 4A-3). Line 2 would consist of approximately 987 km of newly built pipeline and some existing pipeline built in 1957 and 2008 (TM 2013b, Vol. 4A p. 4A-2). The proposed route for the TMEP largely parallels the existing TMPL route (TM 2013b, Vol. 5A). The TMEP would include 12 new pump stations, new storage tanks, and other new components to support Lines 1 and 2 (TM 2013b, Vol. 4A p. 4A-3).

2.1.2. Terminal

TM would expand Westridge Marine Terminal in Burnaby, BC to accommodate increased pipeline throughput and tanker traffic. The expanded marine terminal would require the removal of the existing tanker loading dock and the construction of a new dock complex having the capability to handle Aframax-sized tankers (75,000 to 120,000 deadweight tonnes) (TM 2013b, Vol. 1 p. 1-

11 and Vol. 4A p. 4A-3). The dock complex would also include cargo transfer arms to load crude oil on tankers and vapour recovery and vapour combustion units to capture hydrocarbon vapours (TM 2013b, TERMPOL 3.15 p. 22). Oil for tanker export would be collected and stored in 14 new storage tanks at Burnaby Terminal and delivered to Westridge Terminal via three delivery lines (TM 2013b, TERMPOL 3.15 p. 22 and Vol. 4A p. 4A-3). According to TM (2013b, Vol. 2 p. 2-27), up to 630 of the 890 kbpd in system capacity delivered on the TM pipeline would be for export via the marine terminal.

2.1.3. Tankers

The TMEP would increase tanker traffic from 60 to an estimated 408 tankers per year (TM 2013b, Vol. 2 p. 2-27). Tankers accessing Westridge Marine Terminal would be Panamax-sized (less than 75,000 deadweight tonnes) or larger Aframax-sized tankers, which are the current class of tankers calling at the terminal for the TMPL (TM 2013b, Vol. 8A p. 8A-68 and -71). Tankers would use between two and four tethered tugs to navigate the Vancouver Harbour Area (TM 2013b, TERMPOL 3.15 p. 12). TM would not own or operate the tankers (TM 2013b, Vol. 2 p. 2-27) and thus the tanker owner would be liable to pay any costs associated with an oil tanker spill (TM 2013b, Vol. 8A p. 8A-52). TMEP tankers travelling to and from Westridge Marine Terminal would use existing marine transportation routes (TM 2013b, Vol. 8A p. 8A-67).

2.2. Project Costs

TM (2013b, Vol. 2 App. B) estimates that the capital costs of the TMEP would amount to $5.5 billion nominal to be spent over a seven-year period from 2012 to 2018 (or $4.9 billion in 2012 dollars).[1] Nearly $5.0 billion of the $5.5 billion nominal would be spent in 2016 and 2017 when construction is planned to take place (TM 2013b, Vol. 2 App. B, pp10-11). TM estimates incremental operating costs of $118 million per year after construction is complete (TM 2013b, Vol. 5D). TM expects the TMEP to operate for at least 50 years after which the pipeline and facilities would be decommissioned at an incremental cost of approximately $263 million (or $603 million for both the TMPL and the TMEP) (TM 2013b, Vol. 2).

[1] All monetary figures in this report are in 2014 Canadian dollars unless otherwise specified.

3. TM's Rationale for the TMEP

TM indicates in *Volume 2* of its application (TM 2013b) that building the TMEP is needed because:

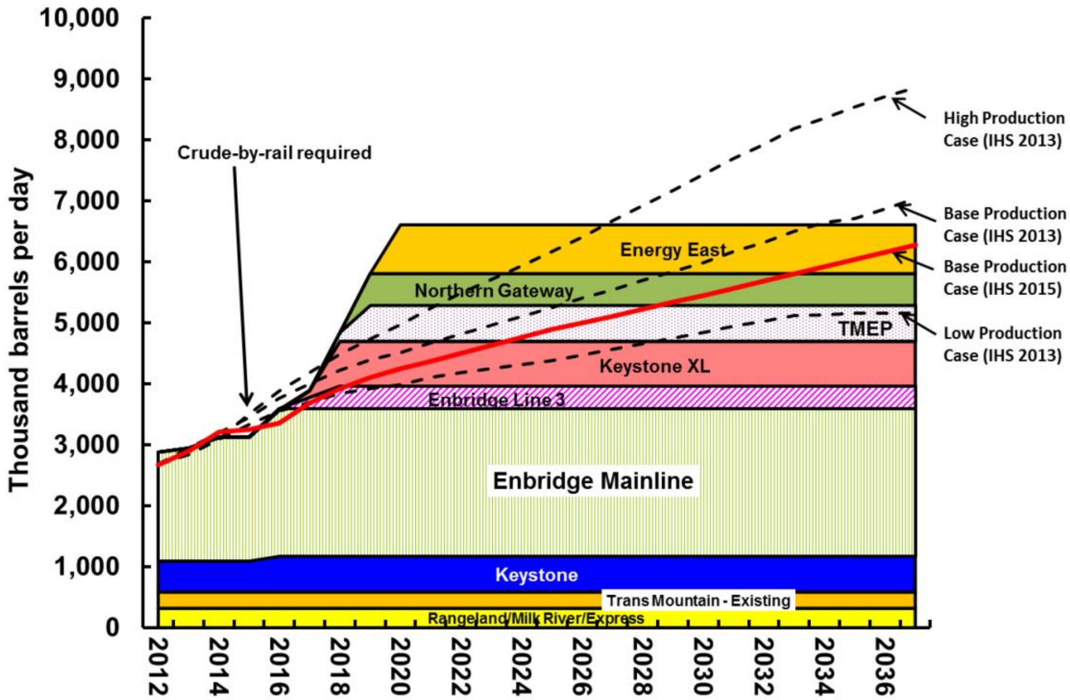
- new pipeline capacity is required to transport the forecast increase in oil production from the Western Canada Sedimentary Basin (WCSB);
- the TMEP will increase netbacks to Western Canadian oil producers by lowering transportation costs and accessing new markets in Asia and the United States;
- construction and operation of the TMEP will stimulate economic activity in Canada and generate tax revenue for government; and
- the TMEP will enhance the flexibility of the Canadian oil sector in the face of increasing market dynamics.

3.1. Need for New Pipeline Capacity

TM asserts that there is a need for new pipeline capacity based on forecasts of oil supply and pipeline export capacity and the fact that some oil companies have signed 15- to 20-year 'take or pay' shipping agreements with TM for 80% (707.5 kbpd) of the nominal capacity of the proposed pipeline (TM 2013b, Vol. 2 p. 2-36-37).

In its evidence submitted on behalf of TM, IHS Global Canada Limited (IHS) (TM 2013b, Vol. 2 App. A) forecasts WCSB oil supply and existing and proposed oil transportation capacity (Figure 2). IHS uses three oil supply scenarios in its original 2013 forecast, a new updated base case scenario in its 2015 update, as well as capacity data for existing and proposed pipelines. IHS estimates in its original submission that there will be 1.8 million bpd of surplus capacity in 2019 if all proposed transportation projects proceed as planned (TM 2013b, Vol. 2 App A p. 45). The surplus capacity estimate has increased in TM's updated forecast to approximately 2.5 million bpd in 2019 (Figure 2). TM now forecasts that if all proposed projects proceed as planned there will be surplus pipeline capacity beyond 2037, even without any existing rail capacity included in the estimates. If rail is included, the surplus capacity estimates would be even higher.

Figure 2. TM/IHS Estimates of Western Canadian Supply for Pipeline Export vs. Pipeline Capacity



Source: TM (2015a, p. 8).

Although IHS estimates that there will be significant surplus pipeline capacity if all planned projects proceed, the IHS forecast suggests that there may be need for some new pipeline capacity in the future. Whether and when TMEP is required depends very much on what oil supply forecast one assumes and what other new pipeline capacity is developed.

Based on IHS's 2015 Base oil production forecast, and assuming Enbridge line 3 and Keystone XL go ahead, additional pipeline capacity would not be needed until 2024. If either Energy East or TMEP are built, there would add enough capacity until after 2028 under the 2015 base case assumption and until after 2037 under the 2013 low production assumption. Adding TMEP capacity based on TM's proposed schedule, therefore, will create unused capacity that will simply divert oil shipments from other pipelines for much of the forecast period. It should also be noted that Figure 2 does not include existing and proposed rail capacity. If rail capacity is included, the unused capacity would be even higher.

3.2. Higher Netbacks for Canadian Oil

TM claims that the TMEP is in the public interest because the project will ensure that crude oil producers and governments receive the highest value for their oil (TM 2013b, Vol. 2 p. 2-37). TM estimated that the TMEP will generate incremental producer revenues of $45.4 billion over the first 20 years of operations resulting in federal and provincial tax benefits of $14.7 billion from increased royalties and corporate income taxes (TM 2013b, Vol. 2 p. 2-37). TM estimates that the TMEP will generate: $37.4 billion higher netbacks by reducing the marginal transportation costs for Canadian oil, and $8 billion by accessing markets in Asia that have higher delivered prices for oil (TM 2013b, Vol. 2 App. A p. 14). In their 2015 update (TM 2015a, p. 10), TM estimates these benefits to amount to $56.3 billion for lower transport costs and $5 billion due to higher prices in Asia. The increase in transportation cost benefits from $37.4 billion to $56.3 billion in the 2015 update is due to an estimated increase in the difference between rail and pipeline transportation costs to the US Gulf Coast (USGC). The 2015 update reduces the estimate of market access benefits due to a lower estimate of the Asian price premium.

3.3. Impact on the Canadian Economy

TM provides an economic impact analysis (EconIA) of the TMEP prepared on its behalf by the Conference Board of Canada. This EconIA estimates direct, indirect, and induced effects from construction and operation of the TMEP on employment, gross domestic product (GDP), and government revenues. As part of this analysis the impact of higher netbacks received by crude oil producers on these economic indicators is estimated (TM 2013b, Vol. 2 App. B p. 7). The EconIA assesses economic impacts of construction over a seven-year period and economic impacts of operations over a 20-year period (TM 2013b, Vol. 2 App. B).[2]

The EconIA estimates economic impacts under two scenarios: the first scenario estimates impacts associated with only the contracted capacity of 708 kbpd, and the second scenario estimates impacts of both contracted capacity and additional spot shipments of approximately 180 kbpd (TM 2013b, Vol. 2 App. B p. 38). According to TM, the first scenario represents a minimum estimate of economic impacts whereas the second scenario represents a maximum estimate (TM

[2] TM states that it only assesses operating impacts over a 20-year period because this is the amount of time for which shippers have signed transportation agreements (TM 2013b, Vol. 2 App. B p. 28).

2013b, Vol. 2 App. B p. 40-41).

The EconIA estimates that the TMEP will generate between 108,310 and 123,221 direct, indirect, and induced person-years of employment during the construction and operation of the project, which translates into 342 direct permanent jobs and a total of 2,514 jobs when multiplier effects are included (TM 2013b, Vol. 2 App. B p.6, p.30, p.36).[3] Furthermore, the EconIA estimates that the project will generate between $18.2 and $22.1 billion in direct, indirect, and induced effects to GDP and up to $4.5 billion in government revenues, with potential for an additional $14.7 billion of increased government revenues related to higher netbacks (TM 2013b, Vol. 2 App. B p. 42).

3.4. Additional Benefits

A report provided by John J. Reed of Concentric Energy Advisors on behalf of TM (TM 2013b, Vol. 2. App. C) also addresses the justification for the TMEP. Mr. Reed states that the TMEP should be assessed in terms of a new dynamic in oil markets that reflects flexibility, diversity of market access, the ability to manage risk associated with competing in numerous markets, and the management of development and operational risk (TM 2013b, Vol. 2. App. C p. 16). Mr. Reed also references the benefits that TMEP will potentially provide Canadians including producers, residents along the pipeline right-of-way, suppliers, governments at the local, provincial, and federal levels, and the overall Canadian economy (TM 2013b, Vol. 2 App. C p. 24).

[3] The use of person-year estimates of employment can exaggerate the significance of the full-time employment effects of the project. The TMEP regulatory application references the creation of 108,310 person-years of employment (TM 2013b, Vol. 1 and Vol. 2 App. B). However, the Conference Board of Canada's EconIA states that the TMEP would create only 342 direct permanent jobs and a total of 2,514 jobs when multiplier effects are included (TM 2013b, Vol. 2 App. B p.30, p.36). A person-year is one person working for one year. Assuming the project operates for 20 years, one permanent job is reported as 20 person-years of employment even though it is one worker employed at one job. The presentation of employment impacts in person-years for operating employment can lead to a misunderstanding of the project's actual employment impacts.

4. Evaluation of TM's Justification for the Project

The evidence provided by TM in *Volume 2* of their application (TM 2013b) to assess the need for the TMEP and whether TMEP is in the public interest is deficient in that:

- it underestimates potential excess pipeline capacity and does not consider the cost of the underutilization of the pipeline capacity the project will cause;
- it exaggerates the potential price uplift and transportation cost savings the project will generate;
- it relies on an assessment of gross, as opposed to net, economic impacts in making its case as to the value of the project from the perspective of the public interest;
- it fails to analyze all of the costs of the project and present any benefit-cost assessment of the consequences of its project in accordance with Treasury Board of Canada guidelines or any other standard guidelines and principles for such an analysis;
- it fails to analyze and present key distributional issues and trade-offs for different stakeholders as is necessary to fully understand the consequences of and public interest impacts of the project; and
- it does not sufficiently analyze and comparatively assess the alternatives to the project.

We discuss each of these deficiencies below in more detail.

4.1. Deficiencies in the Analysis of Need

4.1.1. Understatement of Oil Transportation Capacity

A comparison of IHS's oil transportation capacity estimates to those provided by the

Canadian Association of Petroleum Producers (CAPP 2014) shows that IHS's capacity estimates are 1,731 kbpd lower than CAPP estimates (Table 2). The reasons for IHS's lower capacity forecast are that IHS omits current and planned rail shipments of at least 700 kbpd and has a lower current and potential pipeline capacity of 1,031 kbpd.

Table 2. Comparison of IHS and CAPP Transportation Capacity Estimates

Facility	IHS Estimate (kbpd)	CAPP Estimate (kbpd)	Difference IHS vs CAPP (kbpd)
Enbridge	2,005	2,500	495
Express/Milk River/Rangeland	320	485[1]	165
Trans Mountain	265	300	35
Keystone	590	591	1
Rail	0	300	300
Existing Subtotal	**3,180**	**4,176**	**996**
Enbridge Mainline Expansion	785[2]	720[3]	(65)
Keystone XL	730	830	100
Enbridge Northern Gateway Project (ENGP)	525	525	0
Kinder Morgan TMEP	590	590	0
Energy East	800	1,100	300
Rail[4]	0	400+	400+
Total Existing and Proposed	**6,610**	**8,341**	**1,731**

Sources: CAPP (2014) and IHS (2014, Table 1.2A-1). The transportation capacity estimates underlying IHS's analysis are provided by TM (2014b). Notes: 1. Rangeland and Bow River are included on pipeline maps by CAPP but their capacity is not included in the CAPP report. Capacity for these two pipelines is from Ensys (2010). 2. IHS updated its estimates in 2015 by including Enbridge's Line 3 (370 kbpd) replacement as new capacity (TM 2015a, p. 11). Enbridge filed the Line 3 replacement application to replace and expand capacity of Line 3 with the NEB in November 2014. 3. We have updated the CAPP estimates by adding the 370 kbpd of Enbridge line 3 to the 350 kbpd Clipper expansion in CAPP's pipeline forecast.4. CAPP estimates rail capacity will increase from the current 300 to 1,000 kbpd by 2016 and has the potential to increase to 1,400. CAPP estimates that rail shipments will be 700 kbpd by 2016, well below rail capacity (CAPP 2014, p. 30-33).

In response to information requests (IRs), IHS states that the discrepancy between its pipeline capacity estimates as shown in Figure 2 in our report (section 3.1) and the estimates based on CAPP and pipeline operators is that IHS's estimates are based on available capacity to ship WCSB crude, which is estimated by deducting the capacity required to ship US Bakken oil and refined products on Canadian pipelines (TM 2015c, p. 1-3). While we agree that adjustments have to be made for refined products and US shipments, IHS did not provide any reference to this rationale for these capacity adjustments and has not provided adequate supporting evidence justifying its capacity adjustment assumptions. In describing its adjustment to the capacity of the proposed Energy East pipeline, IHS simply states that:

> *IHS understands that some of this capacity is likely to be allocated to the transportation of Bakken crude. This amount is not known publicly, but for the purposes of this analysis IHS assumed that 300,000 [bpd] of capacity on the Energy East system would be allocated to Bakken crude (TM 2015c, p. 2-3).*

To support this assumption, IHS should provide an analysis of oil transportation supply and demand in the Bakken region. As our analysis shows (section 4.1.3), IHS's assumption regarding Bakken shipments on Canadian pipelines is likely high.

The rationale for omitting rail capacity unless it is needed to cover a shortfall in pipeline capacity is also contrary to IHS's own evidence. IHS (see TM 2013b, Vol. 2 App. A` p. 44) estimates total potential rail capacity of 804 kbpd in Western Canada in 2016 and then excludes this capacity from its supply and demand analysis despite stating in a study prepared for the Energy East pipeline application that

> *we expect that some rail movements would continue, since rail can ship crude oil to refiners that cannot access some crude oil supplies by pipeline (IHS 2014, p. 18).*

IHS also states in the TMEP application that:

> *[r]apid growth is projected in Western Canadian and U.S. northern tier crude on-loading capacity… More project announcements are expected. New rail loading capacity is expected to incorporate efficiency improvements, which will involve the use of unit trains or other efficiency improvements in many cases. This will contribute to improved economics, particularly for facilities that are connected by pipeline (TM 2013b, Vol 2 App. A, p. 43-44).*

CAPP (2014, p. 30-33) estimates current rail shipments of 300 kbpd and forecasts an increase of at least 700 kbpd by 2016, with 2016 rail capacity of 1 million barrels per day (mbpd) with potential for subsequent expansion to 1.4 mbpd. CAPP also notes that some rail shipments are based on longer term contracts, suggesting rail will continue to play a significant role in transporting WCSB oil. US studies (USDS 2014, Vol. 1.4) also document the role of rail and conclude that rail capacity out of the WCSB could increase at a rate required to meet all of the forecast increase in oil transportation requirements to 2030. As discussed below in section 4.3.1, the costs of transport by rail are continuing to decline with efficiency improvements, and TM's own evidence shows that rail costs are competitive with pipelines (Schink 2013, App. A p. 18). Therefore, IHS's omission of existing and planned rail capacity from the transportation supply and demand analysis in the TM application is a serious deficiency that results in a significant underestimate of oil transportation capacity.

We agree with IHS that some adjustments are required to account for the delivery of refined products and US Bakken crude on the Canadian oil transportation system. However, IHS should have made the adjustments in a transparent manner and with sufficient supporting evidence. IHS should also have included an allowance for existing and planned rail capacity instead of including rail only if it was needed to supplement proposed pipeline capacity. These omissions result in a substantial underestimate of transportation capacity and an underestimate of the unused capacity costs to Canada of developing the TMEP.

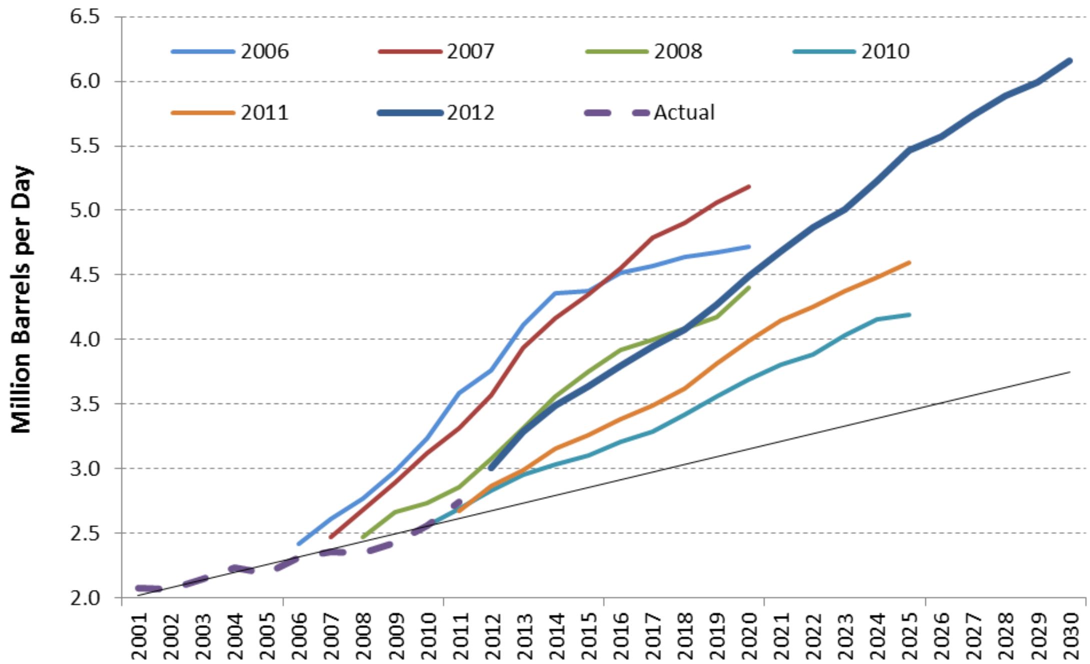
4.1.2. Estimate of Future Crude Oil Supply

TM estimates the need for the TMEP based on a crude oil supply forecast from IHS presented in Appendix A of *Volume 2* in the TMEP application (TM 2013b). Three scenarios are provided in IHS's original 2013 forecast for the 2016 to 2037 time period: base case, high supply, and low supply. IHS states that its base case scenario is consistent with CAPP's forecast (TM 2013b, Vol. 2 App. A p. 7), but higher than the NEB's (2011) crude oil production forecast (TM 2013b, Vol. 2 App. A p. 22). In April 2015 (see TM 2015a), IHS updated its WCSB oil production and export supply forecasts to incorporate the downturn in the oil sector by adding a new base case that is substantially lower than the previous IHS base case (Figure 2 in section 3.1).

IHS's forecasts raise several concerns. First, there is the issue of potential optimism bias in oil supply forecasting. Despite IR requests, IHS did not provide past forecasts to allow for evaluation of IHS' forecasting accuracy. IHS does state, though, that its base case crude oil production forecast is consistent with CAPP's forecasts, which systematically over-estimates production. CAPP explicitly acknowledges optimism bias in its forecast methodology as CAPP seeks to ensure that there is adequate investment in transportation capacity (CAPP 2006, p.6). As shown in Figure 3, the magnitude of overestimation in the CAPP forecasts varies by forecast year. For example, the 2006 CAPP forecast is higher than actual production by more than 800 kbpd in 2011 and 2012, and the CAPP 2007 forecast exceeds actual production by about 300 kbpd from

2009 to 2012 (CAPP 2006; CAPP 2007; CAPP 2008; CAPP 2011; CAPP 2012; CAPP 2013). In all cases, CAPP's forecasts were markedly higher than actual production. Given IHS's stated consistency with CAPP forecasts, IHS forecasts may reflect the same optimism bias.

Figure 3. Comparison of Historical CAPP Forecasts of Canadian Oil Sands Production



Sources: CAPP (2006; 2007; 2008 as cited in USDS 2013, Vol. 1.4 p. 1.4-25; 2011; 2012; 2013).

A second concern with IHS's production oil supply forecasts is optimistic price assumptions. In its 2013 forecast IHS assumed an oil price of about $95 per barrel (Brent) in constant US dollars for the life of the project (TM 2013b, Vol. 2 App. A p. 47). However, since IHS completed its forecast, Brent prices have fallen from $109 (2013 US $) in 2013 to a forecasted $59 in 2015, while West Texas Intermediate (WTI) prices have fallen from $98 to a forecast of $52 in 2015 (US EIA 2015a). In its April 2015 update (see Figure 2 in section 3.1; TM (2015a)) IHS lowered their forecast for western Canadian crude production to reflect lower oil prices. Other forecasters have also cut their Canadian oil production forecasts in response to declining oil prices. CAPP (2015) expects a 33% reduction in oil sector investment in 2016, a 30% decline in drilling in 2016, and a 120 kbpd reduction in production in 2016 relative to the 2014 forecast (which itself reduced the production forecast by approximately 300 kbpd from the 2013 CAPP forecast) (CAPP 2014). The International Energy Agency's (IEA) most recent market analysis (IEA 2015) similarly reduced its Canadian oil production forecast by more than 10% for 2019 due to lower oil prices. However, although IHS reduced its price and supply forecast to better reflect current market conditions, its 2015 update (TM 2015a) still appears optimistic relative to other recent forecasts for the medium to longer term. The 2015 IHS production forecast assumes 2015 Brent prices of $54.38 (2014 US $) rising to $80.26 in 2020 and to $110.48 in 2025, yet the US Energy Information Administration's (US EIA) most recent reference forecast for Brent crude is for prices to remain below $80 (2013 US $) to 2020 and rising to just over $92 in 2025 (US EIA 2015c, p. ES 1-2). Wolak (2015) recently forecasted oil prices to stay in the range of $50-$70 per barrel for the next 10-20 years. While the IHS price forecast for 2020 is similar to the recent 2015 US EIA forecast, IHS's forecast for 2025 is 20% higher than the US EIA forecast (Table 3) and considerably higher than Wolak's forecast. Although the updated IHS forecast better reflects current market conditions, the updated forecast still anticipates a strong recovery in oil markets that may be too optimistic. As IHS states in its update:

> *the IHS long-term outlook, which calls for sustained growth in supply from the Canadian oil sands, has not fundamentally changed in response to the current short-term decline in crude prices. …Short-term oil prices have been volatile historically, and IHS has not materially changed its long-term oil price forecast (TM 2015a, p. 17).*

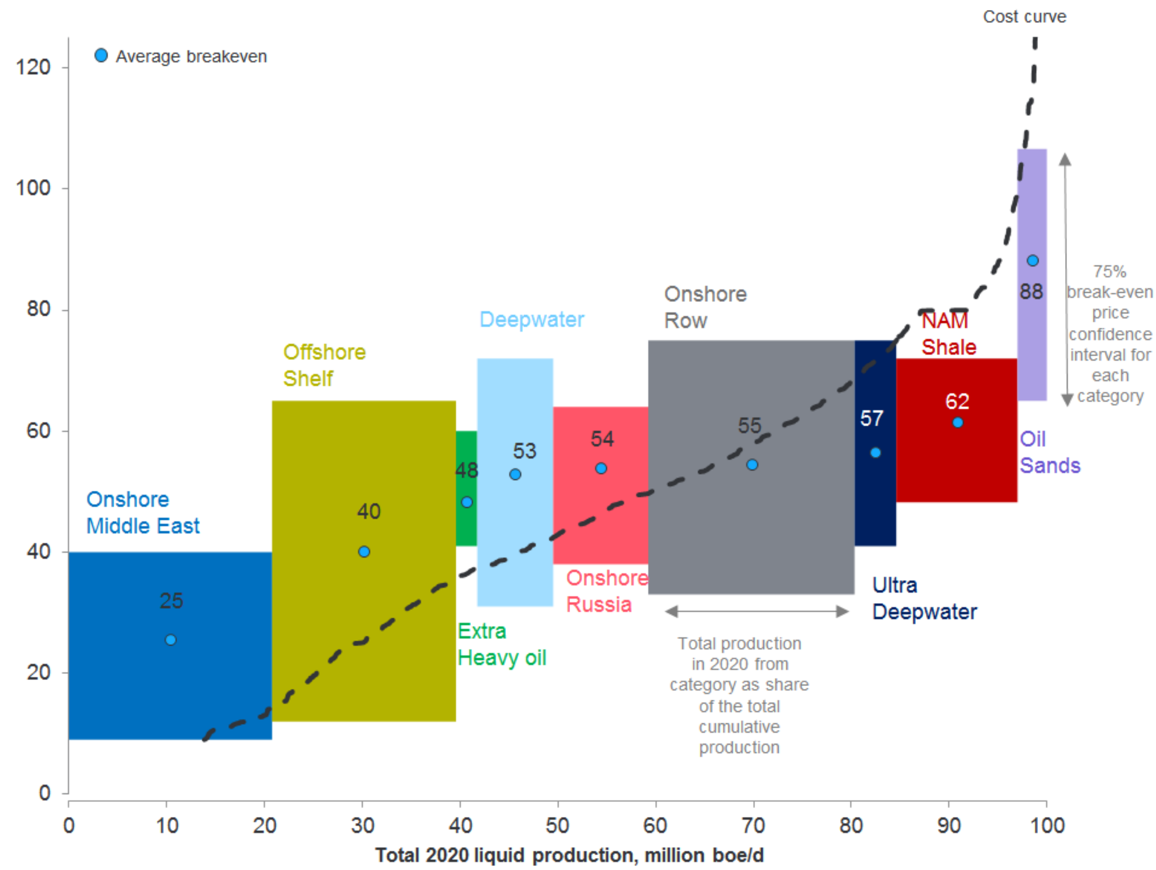
Table 3. Comparison of IHS and US EIA Oil Price Forecasts

Year	IHS (Brent in 2014 US $)	US EIA[1] (Brent in 2014 US $)
2014 (actual)	99.00	99.00
2015	54.38	59.32
2020	80.26	80.41
2025	110.48	92.61

Sources: TM (2015a, p.5) and US EIA (2015a, Appendix A Table A1). Note. 1. US EIA forecasts are updated from US 2013 $ to US 2014 $ by the US CPI for comparison to the IHS forecast.

There is a high degree of uncertainty regarding the future direction of oil prices. But we stress that oil prices can have more significant impacts on Canadian production because Canadian oil sands production (Figure 4, see Oil Sands) is at the high end of the international cost curve (see also IEA (2013, p.454)). Studies by the Canadian Energy Research Institute (CERI) (2014) estimate the WTI prices (2013 US $) needed to justify oil sands expansion are $85 for *in situ* SAGD projects and $105 for mine projects. While some oil sands projects will have higher or lower supply costs than CERI's average estimates, CERI's analysis shows that many previously planned new greenfield projects in the oil sands are unlikely to be developed at current WTI prices. While some other forecasts have lower cost of production estimates for the oil sands, they also forecast slower growth in WCSB production.[4]

Figure 4. Oil Supply Cost Curve (US$ per barrel)



Source: Rystad Energy Research and Analysis (2015).

A third concern with IHS's forecasts is that IHS does not provide a detailed description of the assumptions on which the forecast is based other than oil prices, nor does it explain the methodology used, and how risks and uncertainties are incorporated into the forecast. As a consequence, the reliability and margin of error in IHS's forecast is impossible to assess. Providing detailed descriptions of methods and assumptions, and exploring plausible variation in uncertain model parameters, are standard practice in modelling and forecasting. For example, the NEB, IEA, and US EIA provide transparency with respect to the assumptions underlying their

[4] CERI's estimates are based on a US/Canada exchange rate of .98, but with the recent decline in the Canadian dollar and potential reductions in costs due to slower rates of expansion, the WTI break-even prices will fall. Leach (2015) estimates current break-even costs for new *in situ* projects at just under $50 WTI and new mines at about $63 WTI based on lower exchange rates and lower diluent costs. Leach nonetheless anticipates a downward revision in the oil sands production forecasts due to lower prices.

crude oil production forecasts and show how different assumptions impact their forecasts through sensitivity analyses. The NEB forecasts crude oil production using three cases (high, low, and reference), and all of the NEB's assumptions related to price, macroeconomic conditions, and energy consumption are clearly stated for each case. The NEB's reference case, for example, forecasts supply based upon the current macroeconomic outlook, moderate energy prices, and government policies and programs that were either law or near-law during report preparation (NEB 2013a, p. 1). Similarly, the IEA's *World Energy Outlook* (IEA 2013) uses its New Policies Scenario, which projects production according to the continuation of existing policies and measures and assumes the cautious implementation of policies announced by governments that have yet to take effect. Likewise, the US EIA provides details on their underlying assumptions and the confidence intervals associated with their forecasts (US EIA 2015c; US EIA 2015a).

A final concern is that the IHS forecasts due not appear to factor in the impact of potential climate change policies on Canadian oil production. Recent studies show that implementation of new climate change policies to achieve global climate change targets could severely curtail Canadian oil sands production because of its high production costs (McGlade and Ekins 2015).

4.1.3. Optimistic Forecast of Bakken Shipments on Canadian Pipelines

As discussed in section 4.1.1, TM used lower than actual pipeline capacity in its transportation capacity analysis, later explained in response to IRs on the grounds that downward adjustments were required to account for shipments of Bakken crude on Canadian pipelines. According to its IR responses, TM assumes 625 kbpd of Bakken shipments on Canadian pipelines comprised of 100 kbpd on Keystone XL, 300 kbpd on Energy East, and 225 kbpd on the Enbridge mainline (TM 2015c, p.2-3). No analysis is provided to support these figures and no analysis of transportation supply and demand for the Bakken region is provided.

Information on the supply and demand for oil transportation for the Bakken region is provided in Table 4. The data show that current transportation capacity is two times higher than current oil production, and by 2019 transportation capacity could be triple current oil production if all proposed projects proceed.

Table 4. Oil Transportation Supply and Demand, Bakken Region

	2015 (kbpd)	**2020 (kbpd)**
Pipeline Capacity	827	1,866
Rail Capacity	1,490	1,590
Total Transportation Capacity	2,317	3,456
Production (Jan 2015)	1,195	1,400 - 1,700
Surplus Transportation Capacity	**1,122**	**1,756 - 2,056**

Sources: North Dakota Pipeline Authority (2015b; 2015a) and Kringstad (2015).

Forecasts of Bakken oil production are in the range of 1,400 to 1,700 kbpd by 2020, but the forecasts remain uncertain, particularly in the face of recent declines in Bakken production due to lower prices and declining well productivity (US EIA 2015b). However, even if Bakken production reaches the high end of the forecast (1,700 kbpd), there will still be over 1,700 kbpd of surplus transportation capacity if all planned projects proceed. Therefore, TM's assumption that 625 kbpd (more than half of current Bakken production) will be transported on Canadian pipelines when there is significant excess transportation capacity serving Bakken is a highly optimistic assumption.

4.2. No Assessment of Costs of Surplus Pipeline Capacity

The NEB's *List of Issues* for the TMEP application (NEB 2013d) requires assessment of the commercial impacts of the project (Issue 3). A major commercial impact of the project that is not assessed by TM is the impact of the TMEP on other oil transportation infrastructure.

TM has firm 'take-or-pay' contracts that may justify the construction of the TMEP from the private financial perspective of TM. However, the construction of the TMEP will contribute to unused pipeline capacity across the broader oil transportation sector. The timing and extent of this under-utilization of pipeline capacity will depend on what oil supply forecast one uses, what other projects are built, and how much rail continues to be used, but in all likelihood it would seem to be significant.

IHS's 2013 analysis (TM 2013b, Vol. 2 App. A p. 45) estimates that there could be 1.8 mbpd of surplus pipeline capacity in 2019, more than three times the size of the TMEP, if all planned projects are built. Based on TMEP capital costs per barrel, this represents approximately $16 billion in unused capacity, which would constitute a large net cost to the Canadian oil and gas sector in the form of excess, unused infrastructure, as well as reductions in tax payments flowing to government. Under IHS's new updated base case forecast (TM 2015a), the surplus capacity in 2019 could increase to approximately 2.5 mbpd, and there could be surplus pipeline capacity until after 2037, with consequent effects on unused infrastructure and government tax receipts.

4.3. Deficient Assessment of Predicted Oil Price Netback

IHS (TM 2013b, Vol. 2 App. A p. 16) concludes that the TMEP would increase netbacks for Canadian crude oil producers by an estimated $45 billion over the project's 20 year operating period. These benefits would result from: (1) a reduction in oil transportation costs with TMEP as compared to rail shipping costs to the USGC ($37.4 billion); and (2) access to higher value markets ($8 billion uplift). In its April 2015 update (TM 2015a), IHS increased the estimated netback benefits to $61 billion. There are a number of serious deficiencies in the analyses underlying TM's estimates.

4.3.1. Transportation Cost Savings

A first problem with the IHS analysis is that the transportation cost comparisons between pipelines and rail do not represent the full range of rail options. IHS estimates that rail transportation to the market-clearing point in the USGC is $5 to $6 more expensive per barrel than pipeline transportation based on a comparison of the cost of shipping diluted bitumen (dilbit) by rail and pipeline. However, another option not assessed by IHS is shipping undiluted bitumen by rail.

Raw bitumen requires the addition of diluent such as natural gas condensates to reduce its viscosity to allow for transportation by pipeline. The resulting dilbit is typically composed of 70% bitumen and 30% diluent (USDS 2014, Vol. 1.4 p. 1.4-29). Rail transportation does not require diluent if insulated rail cars are equipped with steam coils to reheat the bitumen, and this type of rail car lowers costs by not having to transport the same volume of liquid as pipelines (USDS 2014, Vol. 1.4. p. 1.4-29). The majority of tank cars manufactured since 2013 are of the coiled/insulated type that carry 100% bitumen (Torq Transloading 2012 as cited in USDS 2014, Vol. 1.4 p. 1.4-82). IHS acknowledges the potential for lowering rail costs by obviating the need for diluent (TM 2013b, Vol. 2 App. A p. 44, footnote 27), but did not incorporate this scenario in its price differential analysis, making its analysis of costs comparisons between rail and pipeline transportation incomplete.

TM's own evidence indicates that when other viable rail shipment options such as using insulated cars are assessed the cost advantage of pipelines (and the estimated benefit in higher netbacks) could disappear (Table 5). TM's evidence submitted for the TMEP toll hearing (Schink 2013, App. A p. 18) provides a cost comparison of transportation of dilbit (70% bitumen and 30% diluent) and undiluted bitumen by rail and pipeline on a per-barrel basis to several origin and destination markets including Edmonton to the USGC and Fort McMurray to the USGC. Schink's conclusion is that dilbit shipments by rail to the USGC are less expensive than pipeline shipments when condensate is backhauled to the origin market, and that bitumen shipments by rail to the USGC are considerably less than pipeline shipments regardless of whether rail cars are returned empty or full of condensate. Schink concludes that "…in Western Canada, rail has become an increasingly cost-effective transporter for crude oil" (2013, App. A p. 18).

Table 5. Comparison of Rail and Pipeline Shipping Costs to the USGC

Origin-Destination	Product[1]	Returned Rail Cars	Cost per barrel		
			Rail	Pipeline	Difference
Edmonton to USGC	Dilbit	Empty	$13.4	$9.0	+$4.4
	Dilbit	Condensate	$8.5	$9.0	-$0.5
Fort McMurray to USGC	Bitumen	Empty	$13.5	$15.1	-$1.6
	Bitumen	Condensate	$7.2	$15.1	-$8.0

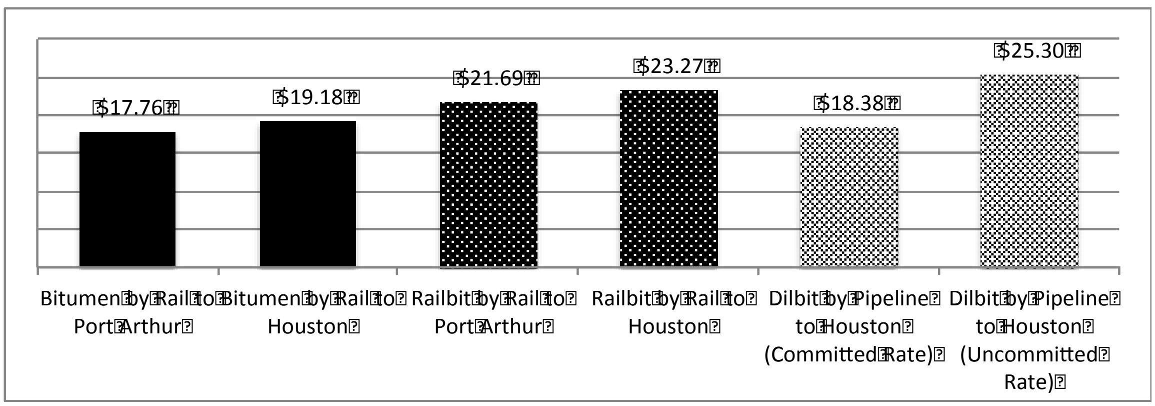
Source: Adapted from Schink (2013, App. A p. 18). Note. 1. Dilbit consists of 70% bitumen and 30% condensate diluent; bitumen in the table represents 100% undiluted bitumen. Pipeline shipments are of dilbit.

Independent analysis prepared by ICF (Undated) for the *Final Supplemental Environmental Impact Statement for the Keystone XL Project* also shows that crude-by-rail shipment of Canadian heavy crude is cost-competitive with pipelines to the USGC.[5] ICF compares costs of transporting crude oil from Western Canada to the USGC by estimating rail and pipeline shipments on a per barrel basis and making the necessary adjustments to ensure that costs of

[5] Note that rail shipment costs from ICF (Undated) and Schink (2013) are not directly comparable since they rely on different assumptions, data, and methods.

shipping dilbit (30% condensate) and railbit (only 15% condensate) are comparable to bitumen.[6] ICF concludes that the cost of shipping bitumen by rail to USGC refineries may be less than shipping bitumen by pipeline (as dilbit containing 30% diluent) to USGC refineries at a long-term committed rate. According to ICF's analysis, both bitumen and railbit shipped by rail are less expensive than shipping bitumen as dilbit at an uncommitted rate by pipeline to the USGC (Figure 5). Furthermore, crude-by-rail estimates in Figure 5 omit the potential for back-hauling diluent on the train's return journey which could create additional savings of $2 to $5 per barrel associated with rail transportation (USDS 2014, Vol. 1.4 p. 1.4-87-89). Other analyses (Fielden 2013; Genscape 2013) also highlight the price advantage associated with crude-by-rail shipments and estimate that rail shipment of bitumen may increase a crude oil producer's netbacks by $4 to $10 per barrel compared to pipeline shipments of dilbit.

Figure 5. Comparison of Rail and Pipeline Shipment Costs



Source: ICF (Undated).

In sum, it is not clear that pipeline deliveries would be less expensive than rail, certainly not by the amount used by IHS to estimate the netback benefit of TMEP. However, even if one were to accept IHS' assumption that rail is more expensive, the netback benefit calculations for the

[6] ICF (Undated) estimates pipeline shipment costs from Hardisty, Alberta to Houston, Texas refineries via the Keystone and Seaway pipelines. Costs associated with pipeline shipments include pipeline tariffs on the Keystone and Seaway pipelines (committed or uncommitted), a penalty for transporting diluent south (i.e., only 70% bitumen is shipped), line fill and storage costs based on a transit time of 20 days, and costs of transporting diluent north to Alberta. ICF estimates rail shipment costs from Hardisty, Alberta to refineries in both Port Arthur, Texas and Houston, Texas for bitumen and railbit. Costs associated with rail shipments include loading and unloading the unit trains, rail freight, railcar lease, a penalty for transporting diluent south (railbit), rail fill costs based on a transit time of eight days, destination movements (i.e., by barge to local refineries in Port Arthur or to refineries in Houston), and costs from transporting diluent north to Alberta. For a complete discussion of these costs see ICF (Undated).

TMEP have another major flaw.

IHS's analysis is based on the assumption that transportation cost savings and increased netbacks for oil deliveries on TMEP would increase the netbacks for ***all*** oil exported from the WCSB. In other words, according to IHS, a small shipment of WCSB oil on rail will set the price for **all** Canadian oil exports. IHS's analysis assumes that the oil market is perfectly competitive and that TMEP shipments are the marginal deliveries establishing (and in this case increasing) the netbacks for all WCSB sales. This assumption is not valid. The crude oil market is not perfectly competitive because of a limited number of buyers and sellers as well as in some cases buyer-seller ownership or other ties. Also, there are long-term transportation and oil sales contracts that will prevent all netbacks adjusting to the netback on marginal deliveries. For example, shippers using long-term contracts will pay the same toll and receive the same netback regardless of whether there is any WCSB oil shipped to the USGC by rail or not.

Finally, even if one were to accept IHS's assumptions that rail transportation is more costly than pipelines and that oil transportation markets are perfectly competitive, IHS's estimate of transportation cost savings is inconsistent with their own analysis that argues that if just some of the other planned pipeline projects proceed there will be sufficient pipeline capacity without using rail. In other words, if TMEP is not built there will be sufficient capacity on these other new pipelines and the rail-pipeline cost differential would not be relevant in determining what if any transportation cost saving benefit TMEP would generate.

4.3.2. Access to Higher Priced Markets

The second component of TM's assertion of a netback benefit with the TMEP is based on accessing offshore markets where Western Canadian crude would supposedly receive a higher price compared to what it would receive from the USGC. IHS estimates a price premium that ranges from $1.76 to $7.72 per barrel in Asia in its 2013 application (TM 2013b, Vol. 2 App. A p. 14), which is reduced to $1.76 to $2.52 per barrel in its 2015 update (TM 2015a, p. 10). IHS, however, provides no evidence to support its forecast of a permanent oil price premium in Asia to 2037.

Although oil prices in Asia have historically been higher than European and US prices by up to $1.50 per barrel throughout the 1990s (Ogawa 2003), price differentials have fluctuated between premiums and discounts (Cui and Pleven 2010; Doshi and D'Souza 2011; Broadbent 2014, p.108-110) with no discernible pattern or trend line with which to forecast a permanent premium 20 years into the future. Doshi and D'Souza (2011) note a recent reversal of the Asian price premium between 2007 and 2009 and conclude that Asia received a discount on crude oil relative to Atlantic markets at this time. Cui and Pleven (2010) suggest that recent discounts on crude oil priced in Asia result from Asia's diversification of crude oil supplies beyond the Middle East and that Asia's increased bargaining power will eliminate the Asian premium.

IHS's assumption of permanent higher Asian prices assumes that the global oil market is comprised of independent regional markets, but regional oil markets are not independent. Rather, regional oil markets are integrated forming in effect a single world market linked by shippers' ability to transport oil between geographic locations according to supply and demand dynamics; if demand and prices rise in one location, producers will increase supply to that location until the oil market equilibrates and price differentials disappear (Adelman 1984; Kleit 2001; Nordhaus 2009; Fattouh 2010; Huppmann and Holz 2012). While there may be short-term impediments in oil markets that restrict adjustments in global supply, such as transportation logistics that result in temporary price differentials (e.g., the glut of oil in Cushing, Oklahoma), the global oil market will work to gradually erode these differences and reduce any short-term oil price differentials over the long-term. As Bruce March, chief executive officer for Imperial Oil, commented, oil is fungible and easily transportable, and oil prices in the Pacific and US will balance as the price of oil in the USGC rises and the price of oil in Asia falls (Vanderklippe 2012). Therefore, while oil prices are uncertain, relying on the assumption of a permanent Asian premium in project evaluation is not supported by the world oil market dynamics and would not be prudent[7].

Finally, it should be noted that a portion of any netback benefit from higher prices, as well as a portion of transportation cost savings, will accrue to non-Canadian shareholders. In terms of the Canadian public interest, any benefits accruing to non-Canadians should be ignored, consistent with the NEB definition of the public interest as inclusive solely of Canadians (NEB 2010a, p. 1) and consistent also with benefit cost analysis guidelines from the Treasury Board of Canada Secretariat (TBCS 2007, p. 12). Although it is difficult to isolate the exact proportion of profits accruing to non-Canadians as a result of TMEP, it is possible to provide an estimate based on the proportion of foreign ownership in the Canadian oil and gas sector. According to Statistics Canada (2013), the percentage of foreign ownership based on profits in the Canadian oil and gas sector averaged 41% for the five years between 2008 and 2012. Consistent with Canadian

[7] There may be some option value in having transportation facilities that allow for exploitation of short-term market disequilibria or locational rents. The benefits, however, would be shorter-term, challenging to exploit given the large number of competitive suppliers, and would have to be weighed against the costs of maintaining the transportation capacity required to exploit different market options.

government guidelines, the after-Canadian-tax profits from higher crude oil prices accruing to foreign shareholders should be deducted from any benefit estimate.

4.4. No Analysis and Consideration of Net as Opposed to Gross Economic Impacts

TM maintains that the TMEP would generate economic “benefits” in the form of jobs, economic output, and government revenues based upon an EconIA done by the Conference Board of Canada (TM 2013b, Vol. 2 p. 2-41-43). It is widely recognized and accepted, however, that gross economic impacts as the Conference Board of Canada estimated do not indicate net effects on the economy and certainly do not in any way indicate the net benefits of the project (Grady and Muller 1988).

To analyze net effects one must recognize how other firms and industries are affected by the project due to direct diversion of expenditures and by the more general economy-wide effects the project may have in terms of impacts on wages, prices, and interest and exchange rates. To evaluate net benefits one must further assess the “opportunity cost” of labour and capital, defined in terms of how the labour and capital would be employed in the absence of the project (Pearce et al. 2006; Ward 2006; Shaffer 2010). In a well-developed economy such as Canada’s, most if not all the labour and capital employed on the TMEP will be employed elsewhere in the economy if the TMEP does not proceed, and the net gain in economic activity generated by the TMEP will be much less, potentially minimal, as compared to the gross impacts estimated by the Conference Board of Canada.

Further to this point, labour market studies document the shortage of skilled labour in Canada, indicating that labour has a high likelihood of otherwise being employed in the absence of the TMEP. As the NEB concludes:

> *[a] shortage of skilled workers is developing as the workforce ages and overall demand for labour increases. According to the Petroleum Human Resources Council of Canada (PHRCC) the oil and gas industry needs to fill 36,000 job openings between 2013 and 2015, as a result of industry activity levels as well as age-related attrition. In the longer term, under a scenario of higher oil and gas prices, the PHRCC is predicting a requirement of 84,000 new hires by 2022. This challenge is being addressed through a number of government and industry initiatives, but a potential labour shortage may increase construction costs and slow the pace of oil development (NEB 2013a, p. 48).*

Recent labour market studies by the BC government similarly forecast tight labour markets in BC and find that in-migration of skilled workers will be required even if no liquefied natural gas (LNG) projects planned for the province are built (BC Statistics 2014). While the recent oil market downturn may take some pressure off the labour market in Western Canada, the assumption that all workers employed on the TMEP will otherwise be unemployed is not valid, and consequently the gross employment impacts of the TMEP cannot be expected to fairly represent net incremental gains to the Canadian economy.

The Conference Board of Canada's estimates of government fiscal benefits provided in TM's application (TM 2013b, Vol. 2 App. B) are also not valid. The estimated gain of $4.5 billion in government revenue from project construction and operation is based on the assumption that all the labour and capital employed by the TMEP would otherwise be unemployed and would therefore generate no tax revenue absent TMEP. Again, most if not all of this labour and capital would be otherwise employed and would generate tax revenue in alternative employment. The Conference Board of Canada's EconIA is also problematic in that it only assesses gross government revenue without considering any potential incremental burdens on government induced by the TMEP such as emergency response and regulatory oversight. As well, the EconIA ignores how tax revenues may be reduced to the extent that TMEP diverts oil and revenues from other shippers. Consequently, the estimated $4.5 billion increase in government revenue estimated by the Conference Board of Canada significantly overestimates the net revenue gain to government.

4.5. Inadequate Assessment of Economic, Environmental, and Social Costs

The NEB's assessment of the public interest value of new pipeline applications requires consideration of the potential negative impacts of projects. However, TM considers only the potential benefits of the TMEP on oil price netbacks and economic output and does not include estimates of the economic, environmental, and social costs of the project despite explicit requirements from the NEB to include these costs in the information provided on the public interest. Such costs include:

- government costs of providing infrastructure and services such as emergency response and regulatory oversight to support the pipeline;
- damages and losses to ecosystem goods and services from pipeline and terminal construction and operation;
- air pollution from construction and operation of the pipeline and marine terminal as well as tanker operations;
- GHG emissions from construction and operation of the pipeline and marine terminal

as well as tanker operations;

- spill accidents or malfunctions that occur during pipeline, terminal, and tanker operations;
- damages and risks to passive use values incurred by Canadians;
- social costs related to the potential conflict associated with opposition to the project, and
- cultural impacts caused by the disruption of traditional and cultural practices resulting from regular project operations and/or spills.

TM's failure to include and quantify these costs in its assessment is a serious omission that results in an incomplete analysis of the public interest value of the TMEP and is contrary to the public interest requirements of the *NEBA*.

4.6. Incomplete Distributional Analysis of Impacts Affecting Different Stakeholders

Federal government evaluation guidelines recommend the need for analyzing the distribution of impacts of projects and policies across different stakeholder groups. As stated in Treasury Board of Canada Secretariat (TBCS 2007) guidelines:

> *[o]ne must ask, "Who are the winners and who are the losers under the policy?" and "By how much does each class of stakeholders gain or lose?" A stakeholder analysis attempts to allocate the net benefits or losses generated by the policy. The output of the stakeholder analysis contains critical information for decision makers, as it indicates which groups will be the net beneficiaries and which groups will be the net losers and by how much (p. 30).*

The Conference Board of Canada's EconIA in Appendix B of *Volume 2* of the TMEP application examines direct, indirect, and induced impacts to GDP, government revenues, and employment from the perspective of the provinces and Canada. The EconIA does not provide a comprehensive analysis of the distribution of potential impacts by stakeholder group (such as First Nations, households in BC, Alberta, and Canada, crude oil producers, and tanker owners/operators, among others) as recommended in federal government guidelines. Further, the analysis of distributional effects in *Volume 2* identifies only the gross economic benefits of the TMEP and fails to examine the distribution of potential costs that stakeholders incur from the project. Consequently, TM is not able to identify who "wins and loses", nor is TM able to identify appropriate mitigation measures such as adequate levels of compensation to address negative impacts borne by particular societal groups affected by the project such as First Nations.

The absence of a comprehensive evaluation of distributional impacts in the TMEP application prevents decision-makers from assessing the economic, environmental, and social costs and benefits to different societal groups in Canada and from determining the appropriate balance of these interests in order to assess the public interest of the project consistent with the *NEBA*.

4.7. Inadequate Compensation Plans

An important consideration in the assessment of public interest and analysis of who gains and who loses from projects such as the TMEP is the nature of the compensation system to mitigate economic, environmental, and social costs incurred by specific stakeholders. Here we focus on just one of the many compensation issues: compensation for damages from a potential tanker spill.

Although TM provides an overview of compensation funds in its Contingency Plan (TM 2013b, TERMPOL 3.18), TM has not provided a comprehensive compensation plan that provides details about the process for mitigating and compensating damages incurred by parties impacted by a tanker spill. The Contingency Plan does not define compensable damages, identify compensable parties, specify methods for determining damage claims, identify funding sources to fully cover all damage costs, or specify dispute resolution procedures. Instead, TM defers compensatory responsibility for tanker spills to the International Oil Pollution Compensation Funds and the domestic Ship-source Oil Pollution Fund, which provides maximum compensation of up to $1.3 billion for tanker spills (TM 2013b, TERMPOL 3.18). It is critical to note, though, that the international and domestic compensation funds only cover damages where a monetary loss can be proven (IOPCF 2011), and consequently many spill damages including environmental damages, social and psychological costs, and passive use damages may not be compensated. Recent evidence shows that compensation actually paid by the International Oil Pollution Compensation Funds represented only 5% to 62% of compensation claimed for six large tanker spills (Thébaud et al. 2005).

4.8. No Assessment of Costs and Benefits of Alternative Projects

The NEB *Filing Manual* (NEB 2013c, p. 4-3) requires proponents to describe other economically- feasible alternatives to applied-for projects and to provide a rationale for choosing the proposed project over alternatives. According to the NEB (2013c, p. 4-4), the proponent must evaluate feasible project alternatives that meet the objective of and are connected to the applied-for project. To justify the proposed project, the NEB recommends that the proponent provide an analysis of the various project alternatives with criteria to determine the most appropriate option (NEB 2013c, p. 4-4). The criteria the proponent should use to evaluate different project alternatives include construction and maintenance costs, public concern, and environmental and socio-economic effects (NEB 2013c, p. 4-3).

The TMEP application (TM 2013b) considers different pipeline corridors and alternative pump station locations in its environmental and socio-economic assessment in *Volume 5A* and *Volume 5B* and identifies some of the criteria referenced by the NEB (2013c) to evaluate alternatives. However, the TMEP regulatory application does not include an analysis of project alternatives that would meet the primary purpose of the TMEP, which is "to provide additional transportation capacity for crude oil from Alberta to markets in the Pacific Rim including BC, Washington State, California, and Asia" (TM 2013b, Vol. 1 p. 1-4) and the more general objective of transporting Alberta crude to world-priced oil markets.

As IHS's analysis for TM indicates, there are a large number of potential transportation projects available and not all the projects or options are required or needed to meet demand. Consequently it is essential to undertake a comparative evaluation of transportation options to identify which option or combination of options is more cost-effective from an economic, environmental, and social perspective. The US government's assessment of pipeline proposals provides a good framework for how to undertake comparative evaluation of transportation options.[8]

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[8] A good example of evaluating alternatives is the US government's *Final Supplemental Environmental Impact Statement for the Keystone XL Project* (USDS 2014). The analysis of alternatives considers three major categories of alternatives and a large number of sub-options under each category including ten alternative scenarios for shipping WCSB oil to the USGC involving rail, a combination of rail and tanker, rail and pipeline, trucking, existing pipeline systems, other recent crude transportation proposals, and additional scenarios that consist of using alternative energy sources and implementing energy conservation measures (USDS 2014, Vol. 2.2 p. 2.2-6). The alternatives were evaluated using comprehensive economic, social and environmental criteria. According to the USDS (2014, Vol 2.2 p. 2.2-1), an evaluation of all feasible project alternatives provides decision-makers and the public with a range of reasonably different options to the proposed project to consider.

4.9. No Assessment of Project Trade-offs

A final major deficiency in the TMEP application is that the regulatory application submitted by TM does not present the major trade-offs of the project in terms of its gains and its costs. The TMEP application contains several sections relevant to evaluating the public interest of the project: *Volume 2* of the TMEP application discusses the economic and commercial implications of the project and contains appendices that estimate the benefits of the project, the need for the project, and the direct, indirect, and induced economic impacts; *Volumes 5A, 5B, 5C* and *5D* contain the socio-economic and biophysical impacts of the project; and *Volumes 7* and *Volume 8C* (including the TERMPOL studies) contain important information related to spill risk. However, TM does not synthesize important information from the different volumes of the regulatory application in a centralized evaluative framework to compare costs and benefits of the project and trade-offs that decision-makers must consider in assessing the project's public interest value. Identifying trade-offs between gains from project benefits and losses from project costs is information needed by the NEB to be able to weigh the impacts of a project to determine whether the project is in the public interest (NEB 2010a, p. 1).

4.10. Summary of Major Deficiencies

The methods used by TM to assess whether the TMEP is in the public interest has a number of major weaknesses. The assessment uses gross economic impacts as the primary measure of the contribution of the project to the public interest instead of net impacts, and the method incorrectly assumes that economic impacts are a measure of benefits without taking into account the opportunity cost of the labour, capital and other resources it uses. TM's analysis overstates the need for and value of the transportation services it provides. The TM analysis also does not estimate many of the costs of the project (e.g., unused capacity, and environmental costs) and does not provide a summary of costs and benefit in a format that allows for identification of trade-offs and comparisons necessary for determining whether the TMEP is in the public interest.

Table 6 provides a summary of these deficiencies. In total we identify 11 major deficiencies related to project need and public interest of the TMEP. Accordingly we conclude that TM's application is incomplete and deficient and the application does not provide decision-makers with the information required to make an informed decision on whether the TMEP is needed and in the public interest. Further, we believe that the evidence submitted by TM shows that the TMEP is not needed as planned, will harm the public interest by generating significant costs in terms of surplus capacity, and will not generate the alleged benefits of higher oil price netbacks.

Table 6. Weaknesses in the TMEP Regulatory Application Addressing the NEBA Decision Criteria

Criterion	Description	Deficiency
Project Need	*An analysis of the supply and demand for the pipeline provides the best available information to enable a sound decision of the need for pipeline capacity*	1. Understatement of oil transportation capacity 2. Optimistic crude oil supply forecast 3. Optimistic forecast of Bakken shipments on Canadian pipelines 4. No assessment of costs of surplus pipeline capacity
Public Interest	*All relevant economic, environmental, and social costs and benefits to Canadians are estimated using the best available information and analysis to facilitate a rational assessment of public interest impacts*	5. Deficient assessment of predicted oil price netback 6. No analysis and consideration of net as opposed to gross economic impacts 7. Inadequate assessment of economic, environmental, and social costs 8. Incomplete distributional analysis of impacts affecting different stakeholders 9. Inadequate compensation plans 10. No assessment of costs and benefits of alternative projects
	Information is presented in a manner that facilitates the identification of trade-offs among the various impacts to enable a reasoned judgment of whether there is a net benefit	11. No assessment of project trade-offs

5. Benefit Cost Analysis of TMEP

A comprehensive and widely-accepted method for evaluating whether projects are in the public interest is benefit cost analysis (BCA). The objective of BCA is to identify all the positive and negative consequences of a project and to assess the relative significance of these consequences to determine whether a project generates a net gain or net loss to society. BCA is based on a well-developed theoretical foundation, its methodology and application is outlined in numerous publications, and it is required for various types of approvals in many jurisdictions including Canada and Alberta (Pearce et al. 2006; Zerbe and Bellas 2006; TBCS 2007; Shaffer 2010; Boardman et al. 2011). Consequently, we will apply BCA to the TMEP to assess whether the project is in the public interest.

The basic steps in BCA are: (1) specify the scenarios that will be assessed, (2) determine standing, (3) catalogue all types of potential impacts of the project and whether they are benefits or costs and to whom, (4) predict impacts quantitatively over the life of the project, (5) monetize impacts where possible and record impacts that cannot be monetized in other quantitative or qualitative terms (6) discount benefits and costs, (7) compute net benefits, (8) perform sensitivity analyses, and (9) make a recommendation (adapted from Boardman et al. 2011).

We acknowledge that BCA has often been criticized for ignoring the distribution of impacts, concealing value judgments, and omitting or under-valuing impacts that cannot be translated into monetary terms. To address these and other concerns we use a modified BCA approach termed *Multiple Accounts Benefit-Cost Analysis* that disaggregates costs and benefits by stakeholder and by type and explicitly includes costs and benefits that cannot be translated into monetary units (Shaffer 2010). We also conduct a range of sensitivity analyses to test how results may change under alternative assumptions. Where applicable we use Canadian benefit cost analysis guidelines published by the federal government (TBCS 2007).

5.1. CBA Overview and Assumptions

We summarize the components of the potential benefits and costs of the TMEP that we consider in our BCA in Table 7. The benefits of the TMEP are revenues associated with transporting WCSB oil to market, the potential gains in netbacks by accessing higher value markets and reducing transportation costs, employment, and tax revenue. The costs of the project are the capital and operating costs of the TMEP, the costs of unused capacity, costs to BC Hydro, plus external environmental costs such as GHG emissions, potential damages from oil spills, and other environmental and social costs, including costs specific to First Nations.

Table 7. Components of our Benefit Cost Analysis

Component	Benefit	Cost
TMEP Pipeline Operations	Toll revenue	Capital and operating costs of TMEP
Unused Oil Transportation Capacity		Reduced net revenues of impacted transportation capacity
Oil Price Netback	Increased netbacks to producers	
Employment	Increased wages and employment generated by TMEP	
Tax Revenue	Net tax revenue gains to government	Net tax revenue loss to government
Electricity		Net cost of supplying electricity to TMEP
GHG Emissions		Damage costs from direct TMEP GHG emissions
Other Air Emissions		Damage costs from TMEP air emissions
Oil Spills		Expected value of TMEP oil spill costs
Passive Use Damages from Oil Spill		TMEP passive use oil spill damages
Other Environmental Costs and Benefits	Other environmental benefits[1]	Other environmental costs[1]
Other Socio-economic Costs and Benefits	Other socio-economic benefits[1]	Other socio-economic costs[1]

Note: 1. These components are identified but not estimated in monetary units in our BCA (see appendix A).

We evaluate and compare two options in our BCA: building the TMEP versus not building the TMEP. The ‘building the TMEP’ and ‘no TMEP’ options both assume operation of existing oil transportation facilities and completion of some new facilities (see below). Following the guidelines of the Treasury Board of Canada Secretariat (TBCS 2007), we assume all Canadians have standing and therefore evaluate the TMEP from the perspective of Canada. For the base case we use the recommended TBCS discount rate of 8%, with sensitivities of 10%, 5%, and 3%. All costs and benefits are reported in 2014 Canadian dollars and are estimated over a 30 year period.

Our oil transportation capacity assumptions are summarized and compared to IHS’s assumptions in Table 8. To allow for easier comparison of our assumptions with those of IHS, we have used IHS’s approach of defining capacity as available capacity to ship WCSB crude, which is estimated by deducting refined petroleum shipments and shipments of US Bakken crude on Canadian pipelines from total capacity. Our base case assumptions are the same as IHS with the following adjustments:

- We include 700 kbpd of rail capacity based on CAPP’s (2014) rail forecast, while TM excludes rail unless there is a shortage of pipeline capacity. We believe our assumption of 700 kbpd is conservative because: actual rail capacity is forecast to be 1,000 kbpd by 2016 with a potential to increase to 1,400 kbpd; rail is increasingly competitive with pipelines for bitumen shipments; and some rail shipments are based on longer-term contracts.
- We exclude the 525 kbpd capacity of the ENGP because this proposed project has no long-term contracts and given the projected surplus pipeline capacity we believe that it is unlikely that the ENGP will to be built.
- We use available capacity for WCSB oil for Energy East of 900 kbpd as estimated by IHS in its evidence provided for TransCanada in the Energy East application instead of 800 kbpd (IHS 2014, p. 152).

Table 8. Comparison of Transportation Capacity Estimates Used in TM/IHS Analysis and in Our BCA

Facility	TM/IHS (kbpd)	Our BCA Base Case[1] (kbpd)
Enbridge	2005	2005
Express/Milk River/Rangeland	320	320
Trans Mountain	265	265
Keystone	590	590
Rail	0	300
Existing Subtotal	**3,180**	**3,480**
Enbridge Expansion	785	785

Facility	TM/IHS (kbpd)	Our BCA Base Case[1] (kbpd)
Keystone XL	730	730
ENGP	525	0
Kinder Morgan TMEP	590	590
Energy East	800	900
Rail	0	400
Total Existing and Proposed	**6,610**	**6,885**

Sources: IHS (2014, Table 1.2A-1). Note. 1. Our BCA capacity estimates are based on IHS estimates from IHS (2014, Table 1.2A-1) and the IHS 2015 update (TM 2015c) which added 370 kbpd incremental capacity for the Enbridge Line 3 upgrade and replacement. IHS estimates are defined as available capacity to ship WCSB crude after deducting refined product shipments and US Bakken crude shipments on Canadian pipelines. Our modifications to IHS capacity estimates include: adding existing rail of 300kbpd to existing capacity and an additional 400 kbpd of rail to new capacity based on CAPP 2014; increasing available capacity on Energy East to 900 kbpd consistent with the IHS market assessment for TransCanada (IHS 2014, p.152); and omitting capacity of the ENGP pipeline due to the low probability of the ENGP being built.

As indicated in Table 8, our assumptions of total WCSB transportation are similar to those adopted by IHS. However, to address uncertainty regarding proposed expansion of oil transportation infrastructure, we conduct the following sensitivity analyses by making the following alternative assumptions to our base case transportation capacity:

1. IHS assumptions (no rail and add ENGP);
2. rail capped at 300kbpd;
3. no Keystone XL with rail capped at 300 kbpd;
4. no Keystone XL and no Energy East with rail capped at 300 kbpd; and
5. ENGP added to our base case.

Our oil supply assumptions use estimates provided by IHS in the TM application and the updated forecast. For our base case we use the updated IHS base case forecast (TM 2015a) and for our higher production sensitivity we use the 2013 IHS base case (TM 2013b, Vol. 2 App. A; TM 2014b, Table 1.2A-1) and for our lower sensitivity we use the IHS 2013 low forecast (see Figure 2). As discussed in section 4 of our report, the updated IHS production price and production forecasts appear optimistic and therefore our base case likely underestimates the quantity and costs of unused capacity.

5.2. Costs and Benefits for Trans Mountain

The costs of the TMEP are the capital and operating costs of transporting the oil as specified by TM in its submission: capital costs of $5.5 billion in nominal dollars to be spent over a seven-year period from 2012 to 2018 (or $4.9 billion in 2012 dollars) (TM 2013b, Vol. 2 App B p. 5); incremental operating costs of $118 million per year (Vol. 5D p. i); and incremental decommissioning costs of approximately $263 million (Vol. 2 p.35).

The benefits accruing to TM are the toll revenues it receives for transporting oil to market. Tolls for the TMEP are set to cover all the operating and capital costs of the pipeline as defined in the TMEP toll hearings. We assume given TM's shipper contracts that TMEP will be fully utilized, or at least in accordance with the utilization rate used to determine the cost recovery tolls. We further assume that the cost of capital used to determine the tolls are equivalent to the BCA discount rate. Under these assumptions, the present value of the TMEP capital and operating costs equal the present value of the toll revenues, and there is no net benefit or cost for the TMEP directly.[9] However, if the TMEP costs are higher than forecast in the toll hearings there will be a net cost because toll revenues will no longer fully cover costs, and if TMEP costs are lower there will be a net benefit because toll revenues will exceed costs.

Previous pipeline projects indicate that there is a propensity for significant cost escalation, which is consistent with other research on large projects (Flyvbjerg et al. 2003; Gunton 2003).[10] Although the record indicates a high risk of cost overruns, the risk may be lower with the TMEP because much of the project uses existing corridors similar to the Enbridge Clipper expansion that was completed on budget. Nonetheless, given past experience it is important to do a sensitivity analysis testing the impact of varying costs on the TMEP's net benefits. Consequently we

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[9] Although the direct operation of the TMEP generates a net present value of zero (benefits equal costs), the operation has the potential to generate other benefits (such as improved market access) and costs which are addressed in other components of the BCA.

[10] Estimates of the capital costs of the Enbridge Northern Gateway project increased by about one-third from $5.5 billion (2009$) ($5.9 in 2012$) as stated in its application (Enbridge 2010) to $7.9 billion as stated in NEB Joint Review Panel Report (NEB 2013b, p. 4). Keystone XL cost estimates increased by approximately 45% between 2012 and 2014, from $5.5 billion to $8.0 billion (TransCanada 2013, p. 40; TransCanada 2015, p. 65). The Mackenzie Valley Pipeline costs have reported to have increased by more than 40% from 2007 to 2013 (Jones 2013). Enbridge's Clipper project is reported to have come in on budget, suggesting that costs overruns are not a certainty (Enbridge 2010, p. 50). Although there are many reasons for these increases such as change in project designs and delays, the record shows a propensity for cost escalation.

undertake two sensitivities: a 20% increase in capital costs, and a 10% reduction in capital costs. We use a higher sensitivity for the increase given the evidence of cost escalation seen with previous pipeline projects. Higher capital costs result in a net cost of $792 million while lower costs generate a net benefit of $396 million (net present value).

5.3. Costs of Unused Transportation Capacity

As illustrated in TM's transportation capacity and export supply analysis (Figure 2), construction of the TMEP will contribute to creation of surplus capacity in the oil transportation sector. This surplus capacity represents capital costs incurred by the oil transportation sector that are not offset by toll revenue. Costs of surplus capacity have been identified as a concern in previous NEB pipeline hearings. In the ENGP hearings, Enbridge (Wright Mansell 2012, p. 144) estimated potential costs of unused capacity of $857 million (2012$), and in the Keystone XL hearings, it was estimated that there would be unused capacity costs of $315-$515 million per year would result in increased tolls for shippers (NEB 2010b, p. 24).

We use two methods for estimating the unused capacity costs of the TMEP. The first method is to assume that the toll revenue received by TMEP to recover its capital costs should only be included as a benefit when the TMEP capacity is required (i.e., when the TMEP is not simply diverting shipments from other oil pipelines). If the TMEP capacity is not required, the toll revenues are not an incremental benefit to the transportation sector – they simply replace the toll revenues that would have been paid to other pipelines. In this method the present value of TMEP capital costs are deducted from the overall net benefits to the extent the capital expenditures were not required to move WCSB oil to market.

A second method to estimate unused capacity costs is to estimate more directly the lost net revenue of the unused capacity on existing pipelines resulting from the diversion of oil to the TMEP. This second approach is what was used by Enbridge in its estimates of the costs of unused capacity generated by the ENGP and Keystone XL pipelines referenced above. In this method, the cost of the unused capacity is defined as the net revenue that would have been generated on other pipelines by the 590 kbpd that is diverted to the TMEP. We estimate the net revenue loss per barrel based on Enbridge's audited financial statements for pipeline operations as reported in their 2014 annual report (Enbridge 2015, p. 66-67).[11] We develop three alternative estimates of net revenue loss per barrel based on different assumptions (Table 9). We use Enbridge's mainline for our base case estimate of unused capacity costs because we are focusing on costs in Canada. However, there will be a propensity by shippers to divert oil to the TMEP that would have gone to further destinations. Therefore we include a sensitivity analysis based on Cushing shipments. Also note that some shipments may be diverted from rail which has a lower net revenue ratio. We address this in two ways: first, we estimate the net revenue per barrel for a combined (50/50) Enbridge mainline/rail assumption; second, we have included several scenarios in which rail is capped at 300 kbpd or eliminated as a shipment option so that the net revenue loss will be primarily or exclusively on pipelines.

The quantity of unused capacity is estimated as the lower of: (1) the 590 kbpd diverted to the TMEP and (2) total unused oil transportation capacity at 95% capacity utilization. As discussed above in our transportation capacity and demand assumptions (section 5.1), we include a number of sensitivity analyses in which we change capacity and oil supply assumptions to test the impact on unused capacity costs. Also, just as increased netback benefits accruing to non-Canadians should be omitted as a benefit, unused capacity costs incurred by non-Canadians should be omitted as a cost. We have not omitted either of these non-Canadian benefits and costs in our analysis due to data limitations. Omitting the proportion of capacity costs accruing to non-Canadians would reduce the capacity cost estimate in our CBA, but as noted above our base case capacity cost estimates are conservative because they exclude the net revenue losses on the US

[11] Enbridge data is used for the net revenue loss estimate because much of the oil shipped on TMEP is likely to be diverted from Enbridge, given that Enbridge is the largest shipper, and as oil shipped on competing pipelines and some rail is under long-term contracts while most of the oil shipped on Enbridge is not. Also, the total new contracted shipments that need to be diverted to fill new pipelines (Keystone XL, Energy East, and TMEP) in 2020 is 2,254 kbpd (TM 2013b, Vol 2 App A p. 46). Therefore, even if all shipments on rail in our base case (700 kbpd) are diverted, an additional 1,554 kbpd would need to be diverted from other shippers, primarily Enbridge. The net revenue loss estimates for Enbridge will provide a reasonable estimation of the net revenue losses incurred by other shippers. Net revenue loss is calculated from p. 66 of Enbridge's 2014 annual report (Enbridge 2015) for their Canadian mainline based on a three year average (2012-14) of revenue less power costs. Operating and administrative costs are not deducted for two scenarios (mainline and Cushing because Enbridge (2015, p. 67) states that operating and administrative costs (other than power costs) are relatively insensitive to throughput volumes. Administrative and operating costs are deducted in the Enbridge Mainline/Rail scenario to provide a lower bound estimate of net revenue loss. As there will be a propensity for shippers to divert oil that incurs higher toll charges, oil shipped to further shipment points will be the most likely to be diverted, subject to other constraints such as contracts and destination oil prices. We acknowledge that oil shipped on TMEP may be diverted from other non-Enbridge facilities that may have different cost profiles and that there is uncertainty regarding the destination of the oil diverted from the Enbridge line. We have addressed this uncertainty by using a range of net revenue loss estimates for different Enbridge shipment options.

portions of Canadian pipelines. The net present value estimates of unused capacity costs are: $2.1 billion for the rail/pipeline scenario, $3.1 billion for the Enbridge mainline scenario, $8.8 billion for the Enbridge Cushing scenario, and $3.2 billion based on the TMEP cost of capital approach.

Table 9. Unused Capacity Costs

Assumption	Unused Capacity Cost (billion $ net present value)
Enbridge Mainline (base case)	3.1
Enbridge Alberta to Cushing toll	8.8
Enbridge Mainline/Rail (50/50)	2.1
TMEP Unneeded Capital Cost Method	3.2

Source: Unused capacity costs are estimated by multiplying the quantity of oil diverted by year by the net revenue per barrel. Enbridge net revenue estimates are on based on three year average net revenue ratios for 2012-2014 from Enbridge (2015, p. 66-67) . For Enbridge Mainline, the net revenue per barrel is estimated by dividing annual oil throughput by annual net revenue. For the Enbridge Alberta to Cushing option the net revenue/total revenue ratio for Enbridge is multiplied by the toll rate for heavy oil for Enbridge tolls as reported in CAPP (2014, p. 42) and converted to Canadian dollars. The Enbridge Mainline/Rail option is estimated by using a lower net revenue estimate for Enbridge based on deducting operating and administrative plus power costs as defined in Enbridge (2015, p. 66) per barrel and applying the operating cost (excluding depreciation) to revenue ratio from CN Rail 2014 to the average revenue per barrel for the Enbridge Mainline. These assumptions for the Enbridge Mainline/Rail scenario will understate net revenue loss per barrel because they include operating and administrative costs for Enbridge (which Enbridge states are relatively insensitive to throughput) and they use average operating cost to revenue ratios for CN (which will overstate short run marginal cost) and apply these to Enbridge's average revenue per barrel. Therefore the cost of unused capacity under this assumption is conservative.

5.4. Higher Netbacks to Oil Producers

TM asserts that a major benefit of the TMEP to the oil and gas sector is increased netbacks by accessing higher value markets and lowering the marginal transportation costs of WCSB oil exports. As discussed in section 4.3 of this report, TM's forecast of increased netbacks due to lower transport costs resulting from the TMEP is in our view not proven or reliable, and therefore we do not include TM's estimate of higher netbacks induced by lower transport costs in our BCA.

The other potential source of higher netbacks identified in the TM application is based on accessing higher priced oil markets such as Asia. We reviewed the merits of this Asian premium in section 4.3.2 of our report and concluded that while price premiums can exist for periods of time due to market constraints and lags in market adjustments, the existence of a permanent long-term price premium is not evident from past price data and is not consistent with the operation of world oil markets. Consequently, it would be unreasonable to assume a permanent price premium in the evaluation of the TMEP. Nonetheless, to test the impact of a price premium we include a sensitivity analysis based on IHS's forecast of an Asian price lift ranging from $1.76 to $2.52 per barrel through to 2037 for TMEP oil shipped to Asia as estimated in the 2015 TM update (TM 2015a, p. 10). The estimated price lift benefit is $ 2.0 billion. However, consistent with federal guidelines (TBCS 2007), we note that the proportion of the price uplift benefit accruing to non-Canadians should be omitted from the benefits. We have not attempted to estimate this proportion because we do not have detailed ownership data on the shippers on the TMEP. However, the proportion of foreign ownership in the oil and gas sector (based on operating profits in the most recent five year period (2008-2012) is 41% so the proportion that should be removed as a benefit is significant.[12]

5.5. Employment Benefits

A potential benefit of the TMEP is providing employment to workers. As discussed in section 4.4 of this report, the economy of Western Canada has been characterized by tight labour markets and it is unlikely that workers employed on the TMEP would otherwise be unemployed. However, given recent developments in the energy sector and the potential of TMEP training and hiring employees through impact benefit agreements, it is possible that there will be an employment benefit, with some hiring of persons who would otherwise be unemployed or employed at a lower wage. Consequently, we include an employment benefit in our CBA.

The measurement of potential employment benefits depends on labour market conditions and hiring policies of companies that are difficult to forecast. To illustrate the potential significance of the employment benefits, a percentage is applied to the wages paid to represent the incremental income that might be earned, or more specifically the income in excess of the labour's opportunity cost (e.g., 5% (Wright Mansell 2012, p. 73); 10-15% (Shaffer 2010)). In the sensitivity analysis we use two scenarios: 5% applied to construction employment income for the base case and a sensitivity of 15% applied to construction and operating employment income to measure the range of potential employment benefits. We use the direct labour income for construction and operating employment incomes based on data in the TMEP application, which we note is high

[12] Statistics Canada's (2014) definition of foreign ownership is based on the country of control. Some countries classified as foreign-owned based on country of control may have Canadian shareholders and some countries classified as Canadian may have foreign shareholders. Therefore, the proportion of profits accruing to non-Canadians may be higher or lower than the Statistics Canada estimate.

compared to other pipeline projects and may therefore overstate the employment benefit (TM 2013b, Vol. 5B).[13] Total estimated employment benefits for the TMEP range from $77 to $284 million (net present value).

5.6. Benefits to Taxpayers

Incremental tax revenues not offset by incremental government expenditures is a benefit to taxpayers. As discussed earlier in section 4.4 of this report, the net increase in tax revenue is much less than the gross increase because the gross increase includes tax revenue that would have been generated in the absence of the TMEP being built. TM's gross revenue estimates also do not deduct any incremental costs to government such as emergency response and regulatory monitoring resulting from the project.

In BCA it is normally assumed that most economic activity-related tax revenue (e.g., income and sales taxes) is not incremental or, for example with respect to the taxes paid by in-migrants, is required to offset the incremental costs of government services and infrastructure needed to accommodate the larger population (Shaffer 2010). Accordingly, tax revenue is not included as a benefit unless the tax revenue is unique to the project (i.e., it would have not been generated in alternative economic activity) and is not required to fund incremental government expenditures due to the project.

In the case of the TMEP there are two streams of tax revenue that could generate net benefits: royalty and income tax revenue from an oil price lift induced by the TMEP, and property tax revenue from the new pipeline and related facilities. As previously discussed, although a permanent oil price lift is unlikely we do include a sensitivity analysis of an oil price lift based on IHS's 2015 updated Asian price premium forecast. In this scenario, we include the incremental tax revenue generated by the higher oil prices as a benefit to government based on the government revenue estimates for the oil price uplift estimated by the Conference Board of Canada (TM

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[13] We use total direct construction labour income (TM 2013b, Vol. 5B p. 7-168) and total direct operating income for the upper bound scenario (p. 7-170). We note that the labour income to capital spending ratio provided in the TM application (approximately 38%) is much than double the ratio used for employment benefit estimates in other pipeline projects as the Northern Gateway (14.55%) (WM 2012, p. 73). Due to lack of detail on the how the labour income estimates were derived in TM's Conference Board report, we are unable to assess the reasons for the difference. We note that using the Enbridge labour ratio would reduce the employment benefit by more than one-half.

2013b, Vol 2 App B). Secondly, although some of the property tax revenue from the TMEP may be required to cover incremental government costs, we assume that most of the TMEP property tax revenue is a net revenue gain unique to the TMEP not offset by increased costs. Therefore, we include property tax revenue as a benefit to government, with the qualification that this will overstate the benefit gain to government to the extent there are offsetting incremental local government costs. TM estimates the incremental property tax revenue of the TMEP at $26.5 million per year, of which $23.1 is paid in BC and $3.4 in Alberta (TM 2013b, Vol. 5B p. 7-185). The net benefit of the property tax is $242 million (net present value).

5.7. Costs to BC Hydro and BC Hydro Customers

TM estimates that TMEP will consume approximately 1,046 gigawatt-hours (GWh) of electricity per year, 520 of which will be consumed in British Columbia (TM 2014a, p. 110-111). Although TM will pay for the electricity, current rates in British Columbia are significantly below the long-run incremental costs of supplying new loads. Consequently, there is a net loss to BC Hydro and its ratepayers equal to the difference between electricity rates paid by TM and the incremental cost of supplying the increased requirements due to the TMEP. BC Hydro's estimated long-run incremental cost of energy is $85-$100 per megawatt-hour (MWh) (BC Hydro 2013) while the average amount paid by TMEP is $38 per MWh (TM 2014a, p. 110-111), resulting in a net cost to BC Hydro of $52 per MWh (based on an incremental cost of $90 per MWh), or $27 million per year. The net cost to BC Hydro and BC ratepayers is $257 million (net present value).

5.8. Environmental Costs

5.8.1. Air Pollution

Installation and operation of the pipeline, construction and operation of Westridge Terminal, and incremental tanker and tug traffic associated with the project would release sulphur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM_{10}; $PM_{2.5}$) that affect human health and ecosystems. Exposure to these pollutants can cause respiratory and heart health effects and increase mortality rates in humans (IMO 2009; US EPA 2009). SO_2 and NO_X are also associated with acid precipitation that can affect forest and aquatic ecosystems (US EPA 2009), and PM deposition contributes to acidification and nutrient enrichment (IMO 2009). TMEP construction and operations would also emit carbon monoxide (CO), volatile organic compounds (VOC), and other hazardous air pollutants including benzene, toluene, ethyl benzene, and xylenes.

TM estimates that some types of air pollution will be reduced with TMEP as tank vapour activation units (TVAUs) will be installed at the Westridge terminal (TM 2013b, Vol. 5A p. 7-86-87). These reductions, however, are not necessarily a benefit of the TMEP if they could be installed or would have been required as a mitigation measure without the TMEP. To reflect this possibility we examine air emission damage costs in our BCA based on two scenarios: one showing the reductions in air pollution estimated by TM based on the assumption that the mitigation measures to reduce emissions could only be implemented if the TMEP is built, and one assuming that the mitigation measures can be implemented whether or not TMEP proceeds.

Our summary of air pollution damage costs estimates from several studies shows that there is a wide variation in air pollutant damage costs due to differing underlying methodological approaches, health and environmental impacts assessed, and physical and socio-economic characteristics of impacted areas (Table 10).

Table 10. Unit Damage Costs for Air Pollution

Pollutant	Social Damage Cost ($ per tonne)[1]			
	Matthews and Lave (2000)[2]	**Muller and Mendelsohn (2007)[3]**	**DEFRA (2011)[4]**	**Sawyer et al. (2007)[5]**
CO	2 – 2,157	n/a	n/a	n/a
SO_2	1,582 – 9,655	1,506 – 2,511	1,929 – 2,711	810 – 2,769
NO_X	452 – 19,516	502	1,087 – 1,586	2,139 – 2,638
PM_{10}	1,952 – 33,280	335 – 837	n/a	n/a
$PM_{2.5}$	n/a	1,841 – 5,523	17,138 – 24,967	5,354 – 6,824
VOC	329 – 9,039	502 – 837	n/a	114 -280

Sources: Matthews and Lave (2000), Muller and Mendelsohn (2007), DEFRA (2011), Sawyer et al. (2007). Notes: 1. All damage costs adjusted to 2014 CDN $. 2. Range for Matthews and Lave (2000) represents minimum and maximum damages. 3. Range for Muller and Mendelsohn (2007) represents average marginal damages in rural areas and urban areas. 4. Range for DEFRA (2011) represents low and high damage values. 5. Range for Sawyer et al. (2007) represents damage in Alberta and British Columbia.

We estimate air pollution costs of the TMEP using the air emission data summarized in Table 10. We generate estimates for three cases: a base case using the midpoint average damage costs, a high estimate using the average upper end damage costs and a low estimate using the average lower end damage costs from Table 10. Based on these assumptions, air pollution from the TMEP could cause between $9 and $427 million (net present value) in social damage costs over a 30 year period. We caution that there is a wide range of uncertainty in damage costs from air pollution and that costs will vary depending on regional factors including the concentration of existing pollutants, exposure to newly emitted pollutants, the population impacted, and the physical and environmental characteristics of the impacted airshed.

5.8.2. Greenhouse Gas Emissions

TM estimates that the TMEP will emit 1,020,000 tonnes of GHG during construction and 479,100 tonnes annually from pipeline, terminal, and marine operations in the TMEP defined study area from Burrard Inlet to Juan de Fuca Strait (TM 2013b, Vol. 8A, p.266; TM 2015c, p.30). Other GHG sources indirectly associated with the TMEP are emissions associated with the extraction and end-use consumption of oil transported on the TMEP and marine transportation outside the 12 mile marine study area. The NEB's list of issues for the TMEP (NEB 2013d) explicitly excludes consideration of impact associated with upstream oil production and downstream consumption and marine emissions outside of the study area. Consistent with the NEB's decision we have omitted upstream and downstream GHG emissions from our analysis. However, we note that the production and consumption of oil are significant and account for approximately 99% of the GHG emissions associated with oil (IHS CERA 2010). Consequently, the emissions from production and consumption of oil transported on the TMEP should be assessed at some point in the project evaluation process.[14] Even if not incrementally caused by TMEP, GHG emissions associated with the production and consumption of oil transported on the TMEP are a concern to many Canadians.

One approach to measuring GHG costs is to estimate the "offset costs" to eliminate or reduce emissions to avoid damage. BC, for example, has a carbon offset program based on a target cost offset of $25 per tonne CO_2e (PCT 2014). However, a recent evaluation of offset programs by the BC Auditor General concluded that offset programs provide inaccurate estimates of offset costs because many of the offsets are based on investments that would have already been made to reduce GHG emissions without the payment and therefore do not represent the costs of incremental reductions (BC OAG 2013).

A second approach is to use abatement costs. Stern (2009) estimated abatement

[14] There is uncertainty whether the new pipeline projects such as the TMEP increase oil production or simply divert oil. Our analysis of the TMEP assumes the oil is diverted and thus TMEP does not result in increased GHG emissions. Even in this scenario it is important for public policy to assess the GHG impacts of oil shipped on the TMEP even though this is not a direct cost generated by the TMEP.

measures to achieve GHG reductions at approximately 30 euros per tonne (approximately $45 Canadian), while Canada's National Roundtable on the Environment and Economy estimates CO_2e prices required to achieve Canada's medium- and long-term goals of reducing GHG emissions by 20% below 2006 levels by 2020 and 65% by 2050 (NRTEE 2009) to be $100 per tonne (2006 $, or $111 in 2012 $) by 2020 rising to $300 by 2050.

A third approach to estimating GHG damage costs is to estimate the social cost of GHG damage. In a recent meta-analysis of the social cost of carbon, Tol (2011) examines 311 estimates of the social cost of carbon in 61 studies from 1991 to 2010. The average mean and average mode marginal cost estimates are $177 and $49 per tonne, respectively (1995 US$). In more recent reviews, Weitzman (2013) and van den Berg and Boltzen (2015) caution that most GHG damage cost estimates – including many reviewed by Tol in his 2011 study – are too low because they do not incorporate the willingness to pay to avoid potentially catastrophic events.

Given the problems with reported offset costs in BC, and uncertainty as to whether offsets would in fact be implemented for the TMEP, we use the social damage cost approach based on damage costs recommended in US government guidelines (US GAO 2014). These US guidelines recommend using a range of damage costs to reflect the range of potential GHG emission damage costs. For our base case we use US government (US GAO 2014) recommended cost of $48 per tonne (2014 CDN $), and for our sensitivity we use the upper range US government cost of $137 per tonne (2014 CDN $). The US government GHG cost estimates escalate in real terms over time. This two tier approach is similar to the approach used by the Canadian government in its regulatory evaluations of carbon emission reduction programs (Canada 2013). Based on this approach, we estimate that net GHG damage costs from the transportation of oil on the TMEP (excluding upstream and downstream emissions) is between $289 million and $916 million (net present value).[15]

5.8.3. Oil Spill Damages

Spills from tanker and pipeline operations associated with the TMEP have the potential to lead to significant environmental costs. We estimate spill costs based on an expected value

[15] A challenge in estimating the GHG impacts of the TMEP is in estimating what the net increase in emissions would be after taking into account potential reductions in emissions from lower shipments on other pipelines. The net increase in emissions will be lower than our gross emission estimate to the extent that GHG emissions are reduced by lower shipments and consequently lower power consumption on other pipelines.

calculated as:

*Annual expected value = p*c*q*

where:

p is the annual probability of a spill (i.e., the inverse of the return period);

c is the damage and cleanup cost per volumetric or areas unit of spill (barrels or hectares); and

q is the size of the spill (in barrels or hectares).[16]

We use oil spill probability and damage costs estimates for spills based on the findings of Gunton and Broadbent in their oil spill risk assessment report of TMEP (Gunton and Broadbent 2015).[17]

5.8.3.1. Tanker and Terminal Spills

There is considerable uncertainty in forecasting the frequency of tanker spills. To reflect this uncertainty we use two spill frequency scenarios. For the base case we use tanker at sea and at port probabilities based on the US government's oil spill risk model OSRA which is the standard method used by the US government to assess marine oil spill probabilities.[18] Given the uncertainty in spill probability forecasts, we also complete a sensitivity analysis based on TM's tanker and terminal spill probability estimates. We note that the evaluation of oil spill risks by Gunton and Broadbent (2015) identify some 27 deficiencies with the TM spill probability estimates, some of which result in an underestimate of spill risk. Also, TM's higher-end (lower probability) tanker spill return period estimates are higher than estimates generated by other studies and methods. Consequently, we use one of TM's mid-range probability estimates (called New Case 1) with a return period of 90 years for any size tanker spill. Table 11 presents the parameters used in our oil spill damage costing.

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[16] This approach is consistent with BCA theory (Zerbe and Bellas 2006) and was the approach that Enbridge used to assess the costs of oil spills in its NGP application (Wright Mansell 2012).

[17] We provide only a brief summary of the spill probability and costs assumptions here. For more detailed background consult Gunton and Broadbent (2015).

[18] The model has been peer reviewed and used in a variety of environmental impact assessment reports and the model's data have been recently updated to include impacts of mitigation measures adopted over the last few decades to reduce the probability of tanker spills (Anderson et al. 2012).

Table 11. Summary of Major Marine Spill Parameters for Oil Spill Cost Estimates

	Base Case Scenario: US OSRA	**Sensitivity Analysis (based on TM's New Case 1 spill probabilities)**
Return Period[1]	14 years	90 years (Tanker) 22 years (Tanker and Terminal)[2]
Annual Probability	0.071	0.011 (Tanker) .04 (Tanker and Terminal)
Mean Size Tanker Spill	34,932 barrels	56,700 barrels [3]
Damage Cost [4]	$42,700/barrel	$42,700/barrel (Tanker) $20,649/barrel (Terminal)

Sources: Gunton and Broadbent (2015), Anderson et al. (2012), TM (2013b, TERMPOL 3.15; 2015b). Notes: 1. The return periods for the US OSRA scenario are combined port and at-sea spills, while the 90 year return period for TM Case 1 is just at-sea spills. 2. The return period of 22 years for the sensitivity analysis scenario is the combined return period terminal and at sea spills. Actual spill costs are calculated by using the return periods for terminals and tankers separately (not combined) 3. Mean size spill for TM New Case 1 is based on Wright Mansell's (2012, p. 77) estimate of the average size tanker spill. 4. Costs are based on Wright Mansell (2012, p. 77) updated to 2014 CDN $ and rounded to the nearest 100 dollars. Estimation of spill damage costs for the sensitivity scenario sums the cost of at-sea spills at $42,700 per barrel and terminal spill costs. Terminal spill costs are estimated by using a terminal probability return period of 34 years for spills <63 barrels and 234 years for spills > 63 and <629 barrels; spill damage costs for TM New Case 1 terminal spill costs based on TM's (2013b, Vol. 7 App. G p. 24) estimated cost of $20,649/barrel updated to 2014 dollars.

We use the damage cost of spills of $37,500/barrel (2012 $) as estimated by Wright Mansell in their BCA of the ENGP Project prepared for the NEB hearings updated to $42,700 (2014 $) (Wright Mansell 2012, p. 77).[19] This estimate is comprised of clean-up costs ($15,000/barrel) plus damage costs ($22,500/barrel) and is based on an extensive review of the tanker spill cost literature. Wright Mansell conclude that their spill cost estimate is at the high end of the estimates in the literature but justify it on the grounds that "higher unit costs should be used in cost benefit analyses where public safety and risk concerns are being evaluated for a hypothetical event" (Wright Mansell 2012, p. 81). While we agree with Wright Mansell on the use of a conservative approach when examining the potential costs of oil spills, we caution that the Wright Mansell estimate may underestimate actual spill costs.

Wright Mansell's spill cost estimate relies on studies from Kontovas et al. (2010) that

[19] Updating dollars combines inflation and US/Canada currency exchange adjustments.

estimate tanker spill cost data from the International Oil Pollution Compensation Fund (IOPCF) which itself has several weaknesses. First, the cost data from the IOPCF dataset represent only the amount of money the IOPCF agrees to compensate claimants, and this amount is often less than the amount actually claimed (Thébaud et al. 2005).[20] Second, IOPCF payments are limited by maximum pay-out limits set by the funds and therefore only compensate a portion of total spill damages if damages exceed the fund limits.[21] Third, IOPFC data excludes several types of damage costs including non-market use values and passive use values. Fourth, tanker spill cost data represent world averages that are not adjusted for geographically-specific differences in damage costs to the environment impacted by the spill. Costs of spills can vary significantly depending on the characteristics of the area impacted, the conditions at the time of the spill, the spill response, and the characteristics of the oil spilled (Vanem et al. 2008). For these reasons, Wright Mansell's $37,500 per barrel damage cost (2012 $) is not a conservative estimate.

For terminal spills we use the probability and clean-up cost estimates contained in the TMEP application (TM 2013b, Vol. 7 App. G p. 24). Terminal costs are only calculated for marine spill scenario 2 (New Case 1) and not the OSRA estimates because the OSRA already incorporate port spills in the return period estimates.

5.8.3.2. Pipeline Spills

Alternative estimates for pipeline spill probabilities are summarized in Table 12. For our base case we use the probabilities and average size spills based on PHMSA data, which we consider the most comprehensive data set on pipeline spills publicly available and is used by the US government in its Keystone XL environmental impact assessment (USDS 2014). Note that PHMSA return periods are between the return periods based on Enbridge historical spill data and the return period estimated by TM.

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[20] Thébaud et al. (2005) determine that the percentage of compensation claimed from the IOPCF compared to compensation actually paid to claimants for six large spills (*Amoco Cadiz*, *Tanio*, *Aegean Sea*, *Braer*, *Sea Empress*, and *Erika*) ranged from 5% to 62%.

[21] For example, victims of the 38,000 tonne (278,500 barrel) *Prestige* oil tanker spill only received €172 million from the 1992 Civil Liability Convention and the 1992 International Oil Pollution Compensation Fund, which represented only 2% of the total long-term spill costs (Liu and Wirtz 2006).

Table 12. Comparison of Pipeline Spill Risk Estimates for TMEP Line 2 [1]

Source of Spill Rates	Size and Type of Spill	Return Period (years)
TMEP	Line 2 Rupture	2
NEB	Line 2 spill (> 9 barrels)	2
PHMSA	Line 2 spill (any size)	0.5
Enbridge	Line 2 spill (any size)	0.3

Source: Gunton and Broadbent (2015). Note. 1. Return periods are for only TMEP Line 2 which comprises 540 kbpd of the 590 kbpd of the TMEP, and therefore our estimates of pipeline spill costs may under-represent the spill costs for the TMEP because about 10% of incremental TMEP oil shipments are excluded.

Estimates of pipeline spill damage costs range from about $3,000 to $167,000 per barrel depending on the size of spill, the type of oil, and the area impacted (Table 13). We use the PHMSA average spill damage cost of $15,000/barrel (weighted average of ruptures and leaks) which is in the mid-range range of spill cost estimates because it is based on a large number of spills and is consistent with the PHMSA average spill size and probability data that we use (PHMSA 2014b; PHMSA 2014a).

Table 13. Summary of Alternative Spill Cost Estimates per Barrel for Pipelines

Type of Spill[1]	TMEP Application	BOSCEM	PHMSA 2010-2014	Enbridge Line 6B	ENGP Application (2012$)
Leak	$28,098 – $86,456	$12,697 – $167,244	$3,188	n/a	$9,800
Rupture	$6,484 - $16,128	$3,022 – $48,858	$30,750	$60,177	$14,000

Sources: TM (2013b, Vol. 7), Etkin (2004), PHMSA (2014b) Enbridge (2015), and Wright Mansell (2012).

However, we caution that the PHMSA cost data may underestimate average spill costs by excluding some relevant socio-economic and environmental costs. For example, the PHMSA dataset includes costs to non-operator private property damage although it is not clear whether these costs include compensation for individuals or businesses whose livelihoods have been disrupted and groups whose cultural activities have been disrupted. Similarly, although PHMSA data include costs to remediate the environment, it is uncertain what portion of total environmental cost is covered by the remediation expenses. For example, excluded damage costs could include compensatory damages to the public for loss of use of the environment and lost ecological services while the spill site is recovering. Third, spill costs do not include passive use values that reflect the value that individuals place on the protection or preservation of resources or psychological costs associated with factors such as stress and dislocation of impacted parties. We also acknowledge that to the extent that reduced shipments on other pipelines lower oil spill risk, the net increase in North American oil spills may be lower than our estimates for the TMEP. Although reduced shipping volumes on existing pipelines may reduce the frequency of spills, the magnitude of reduction is difficult to determine and may be less than the increased risk on the new pipeline, given that spill risk is function of volume and the total length of the pipeline system, both of which would increase with new pipeline capacity.

5.8.4. Passive Use Damages

Passive use values are the values that people place on the protection or preservation of natural resources and the environment that they may not directly use (Freeman 2003; Kramer 2005). Estimating passive values is challenging and for some stakeholders and First Nations monetary estimation of passive values may not be viewed as possible or appropriate. Nonetheless, passive values exist and should be taken into account in assessing the costs of project development.

A common method for estimating passive use values is a contingent valuation study that relies on surveys to ask stakeholders to place a value on specific resource and environmental assets (Carson et al. 2003). For the TMEP, stakeholders could be asked how much they would be willing to pay to eliminate the risk of a major tanker spill in the Georgia Basin or how much compensation they would require to accept the risk posed by increased tanker traffic. This type of contingent valuation study for the TMEP has not been done by TM.

A second approach is the benefit transfer method that adopts damage cost values from a contingent valuation study conducted elsewhere. This approach is recommended when there is insufficient time and resources to complete an original valuation study (Brouwer 2000; Boardman et al. 2011). Good practice in benefit transfer includes selecting appropriate transfer studies that: have similar environmental characteristics and similar non-market commodities being valued; rely on good data; and use sound economic methods and empirical techniques (Boyle and Bergstrom 1992; Desvousges et al. 1992).

We estimate potential passive use values for marine oil spill risk for the TMEP using the benefit transfer method based on two studies estimating WTP to prevent damage from oil spills in Alaska and California. The first study completed by Carson and Hanneman (1992), and updated by Carson et al. (2003), estimates how much US residents would be willing to pay to prevent oil spill damage from another oil spill similar to the *Exxon Valdez* oil spill (EVOS) disaster.[22] Another contingent valuation study from Carson et al. (2004) estimates the amount that households in California would be willing to pay to prevent oil spill damage along the California Coast.[23] The Carson studies are among the most sophisticated contingent valuation studies for assessing passive use values.[24]

The per household willingness to pay (WTP) estimated in the two Carson studies are similar despite the different oil spill scenarios and populations surveyed. The EVOS study (Carson et al. 2003) estimates a lower bound mean WTP value of $53.60 (1991 US $) per household and an upper bound value of $79.20 (1991 US $). The California oil spill study (Carson et al. 2004) estimates a lower bound of $76.45 (1995 US $), which is in the mid-range of the EVOS estimates after adjusting for inflation.[25] Carson et al. (2004) caution that the results between the two studies are not directly comparable because of the differences in the scenarios and populations tested (Table 14).

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[22] The *Exxon Valdez* ran aground on Bligh Reef on March 24, 1989 releasing 258,000 barrels of crude oil that contaminated 1,900 km of shoreline and spread over 750 km from the point of impact. The EVOS caused short- and long-term impacts to marine vegetation, marine invertebrates, fish and fish habitat, marine birds, marine mammals, the regional economy, and subsistence activities of Alaska natives (EVOSTC 2010). As of 2010, 19 of the 32 environmental and human resources injured by the spill have yet to recover (EVOSTC 2010).

[23] Carson et al. (2004) do not define the volume of oil spilled in the California oil spill study in order to focus on the damage that the spill would cause. Instead, the authors provide a description to survey respondents of the spill effects resulting from the harm that is expected to occur from moderately large spills along the California Coast. Carson et al. (2004) avoid mentioning the EVOS in the survey to prevent respondents from answering questions with the belief that they were valuing spill prevention from a spill the size of the EVOS, not comparatively smaller spills along the California Coast.

[24] The courts and independent experts scrutinized the study's results and the study underwent the peer review process for refereed publications when it was published in *Environmental and Resource Economics* in 2003.

[25] EVOS estimates are $60 and $89 in 1995 $.

Table 14. Comparison of EVOS and California oil spill Studies

Study Feature	EVOS Study	California Oil Spill Study
Spill location	South Central Alaska Coast	Central California Coast
Spill prevention mechanism	Escort ship program that would prevent a second EVOS over the next 10 years	Escort ship program that would prevent cumulative damage from oil spills along the California Central Coast over the next 10 years
Description of injuries from a spill	1,000 miles of shoreline oiled 75,000 to 150,000 bird deaths 580 otters and 100 seals killed 2 to 5 year recover period	10 miles of shoreline oiled 12,000 bird deaths Many small plants and animals killed 10 year recovery period
Payment vehicle	One-time increase in federal income taxes	One-time increase in state income taxes
Residents sampled	United States	California

Source: Adapted from Carson et al. (2004).

While undertaking a contingent valuation study specifically for the TMEP would be the most accurate way of estimating passive use values for this project, the two contingent valuation studies by Carson et al. (2003; 2004) on oil spill prevention can provide an order of magnitude assessment of the monetary cost of oil spill risk created by the TMEP because the Carson studies used best practices methods, are assessing the WTP to prevent marine oil spill risk, and the BC study area has many similar biophysical and socio-economic characteristics to those of Alaska and the California Coast. Nonetheless there are a number of issues and qualifications that should be noted.

One issue in using the Carson studies is that they are based on the WTP to prevent oil spills. Another way to frame the question is to ask individuals what compensation they would require to accept the increased risk of an oil spill. Values derived from asking the willingness to accept (WTA) question are significantly higher than values derived from asking WTP because one's WTA for a change that is perceived as a loss tends to be valued much more highly than one's WTP to prevent the loss (Rutherford et al. 1998; Horowitz and McConnell 2002; Knetsch 2005). Horowitz and McConnell (2002), for example, evaluated 45 studies with WTA/WTP ratios and found that WTA values were on average 10.4 times higher than WTP values for public and non-market goods.

Determining which measure is appropriate depends on prior rights regarding the ownership of the resource or the reference point that individuals use to value the underlying good or service (Knetsch 2005; Zerbe and Bellas 2006; Shaffer 2010). Unlike private goods defined by legal entitlement, the marine environment along the BC coast is collectively held. There is no consensus on whether WTA or WTP is the most appropriate in cases involving collective ownership cases, with some arguing that WTP should be used (Mitchell and Carson 1989) and others concluding that WTA is more appropriate because proposed projects will alter the status quo, which stakeholders perceive they have a right to maintain (Knetsch 2005). However, in the case of increasing oil spill risk, Carson et al. (2003) state that WTA is a more appropriate measure because oil spills result in a loss of values relative to the status quo. We agree with Carson et al. (2003) that WTA is the most appropriate measure for oil spill risk but we provide both WTP and WTA estimates with the qualification stated by Carson et al. (2003) that the WTP is a conservative estimate of passive value damages.

Another issue with applying the Carson et al. (2003) WTP estimates is whether to adjust the potential passive use damage estimate by the probability of a spill to give expected values, or to assume that the survey respondents are already providing an estimate of the expected value because they are being asked what they would be willing to pay to reduce the likelihood of tanker spill damage from its current probability to zero. Both the EVOS and California contingent valuation studies by Carson et al. (2003) are structured in a way that asks what people would be willing to pay to reduce the oil spill damages from the current likelihood to zero risk of damage. Therefore, respondents are providing a WTP that does not need to be adjusted for likelihood of occurrence of a spill. However, although respondents were provided with some information of the likelihood of spills, it is unclear how respondents perceive probabilities of spill damage with and without the spill damage prevention measures they are being asked to pay for. Therefore we conduct a sensitivity analysis scenario in which we test the impact of adjusting the passive value damage estimates by the probability of a large spill occurring to generate an expected value.

Carson et al. (2004) found that the WTP varies with a number of factors including the distance that respondents lived from the impacted site. We expect that this same relationship would hold in Canada, with those closer and those more familiar with the Georgia Basin having higher WTP and WTA values than those further away or less familiar. Although the WTP we are using should already incorporate this because they are based on a national survey, we develop a scenario in which we only apply the WTA only to BC households in addition to scenarios that include all Canadian households, with the qualification that the national survey results likely underestimate the WTP of BC residents to avoid marine oil spill risks.

To estimate passive use values for the TMEP tanker spill risk we use the upper and lower bound of Carson et al. (2003) EVOS study estimates of US household WTP. Given that these estimates are based on a national survey of Americans, we also use a national approach and multiply WTP (adjusted to 2014 Canadian $) by the total number of households in Canada.[26] To provide an order of magnitude estimate of potential WTA values we adjust WTP estimates with the WTA/WTP ratio of 10.4 for public and non-market goods from Horowitz and McConnell (2002). We also provide an estimate of the WTA applied to just BC households and an estimate based on adjusting the WTA for Canadian households for large oil spill probabilities. We use the upper bound WTP for Canadian households for our base case ($ 2.0 billion) because this scenario is the most consistent with the national parameters of Carson et al.'s (2003) study and the upper bound better reflects the increase in the WTP that is likely to have occurred since the study (1991) due to the increase in real incomes.

The alternative estimates of the risk of marine spills to passive use value range from a low of $1.4 billion based on WTP for Canadian households to a high and $21.1 billion based on WTA for Canadian households (Table 15). Our base case of $2.0 billion (upper bound of WTP for Canadian households) is at the low end of the range and represents a conservative estimate because it is based on WTP. For our sensitivity analysis we use the mid-point of the WTA range for Canadian households ($17.7 billion).

Table 15. Estimate of Passive Use Values for Preventing Oil Spill Damages

Scenario	Total Passive Value Estimate to Prevent Marine Oil Spill Damage (million $)
WTP Canadian households	1,371 – 2,026
WTA BC households	2,340
WTA Canadian households (mid-point WTA adjusted for spill probability)[1]	3,947
WTA Canadian households	14,261 - 21,073

Note. 1. Expected value estimate is based on US OSRA probability for spills >10,000 barrel applied to the mid-point between the upper and lower bound WTA.

[26] We adjust lower and upper bound WTP values from the Carson et al. (2003) study for inflation, convert US $ to Canadian $, and aggregate the results to reflect the number of households in Canada in 2011 from Statistics Canada data.

There are several qualifications with respect to our estimates of passive value damages of the TMEP that should be noted. First, the calculations of passive use reflect the values, morals, and attitudes of American society and are based on WTP values to prevent a major oil spill in Alaska, not BC. Canadians may value passive use damages impacted by a spill in BC differently than Americans value of Alaskan spill damage. Second, although we use the upper end of the Carson et al. (2003) WTP range for our base case, we do not adjust their WTP values for increases in median household incomes since the study was conducted even though Carson et al. (2003) observe a strong association between higher incomes and a higher WTP to prevent another EVOS. Third, we estimate WTA for passive use damages based on a ratio for public and non-market goods from Horowitz and McConnell (2002) that may be higher or lower than the actual WTA for TMEP tanker oil spill risk. Fourth, Carson et al. (2003) characterize oil spill damages as short-term in their survey, with the environment recovering within five years (Carson et al. 2004, p. 194) yet the research on recovery of the Alaska coastline from EVOS shows that environmental recovery from oil spills tends to be much longer, with only 10 of the 32 environmental and human resource categories monitored having recovered 20 years after the oil spill (EVOSTC 2010). Given that potential damages from a TMEP oil tanker spill could persist longer than stated in the EVOS study survey, passive use damages could be higher than Carson et al.'s (2003) estimates. The Carson et al. study was also done following a major oil spill and the WTP *ex post* a major spill may be higher than the *ex ante* WTP to prevent a future spill. However, the similarity in *ex ante* WTP estimates in Carson et al.'s (2004) California study suggests the differences between *ex ante* and *ex post* may not be significant. Finally, we again caution that relying on estimates from a benefit transfer method is inferior to undertaking a contingent valuation study applied to the TMEP case, which may produce higher or lower results than the benefit transfer method. We also caution that for some individuals, stakeholders, and First Nations there may be no amount of monetary payment that could compensate for oil spill damages.

Another issue raised by some is that the Carson et al. (2003; 2004) studies may not be relevant to assessing passive use damages from oil spills in BC because the mitigation measures (i.e., escort ships and double-hull tankers) that respondents were asked their WTP for in the survey will be provided by projects such as ENGP and TMEP (Wright Mansell 2012). This critique is based on a misunderstanding of the methodology. The mitigation measures used in the Carson studies asked respondents how much they would be willing to pay to implement mitigation measures to *prevent* oil spill damages, not reduce the likelihood of spill damage. Thus while mitigation measures such as escort tugs and double-hull tankers are used in the survey to make the survey realistic, the underlying good that respondents are willing to pay for is prevention of spill damage, not the reduction in likelihood of spill damage. The fact that the TMEP may adopt similar mitigation measures may affect respondents' perception of the risk and their WTP to reduce it, but it does not eliminate the risk, which is what respondents were asked their WTP for. Consequently, Carson et al.'s (2003) estimates are not invalidated just because the TMEP may adopt similar mitigation measures similar to those used in the survey. Another issue is the potential double counting of use values and passive values. A contingent valuation survey of British Columbians WTP to reduce oil spill risk, for example, will capture both passive values and use values, the latter of which are already included in the spill cost estimates. However, given that Carson et al. (2003) surveyed non-Alaskans, the WTP estimates are unlikely to have included much in the way of use value.

5.8.5. Damages to Other Ecosystem Goods and Services

The TMEP would cause damages to a variety of other ecosystem goods and services (EGS) not already covered in previous subsections of section 5.8 of our report. Construction, installation, operation, and maintenance of project facilities would result in habitat destruction, fragmentation of terrestrial species, loss of flora and fauna, changes in quality and supply of groundwater, and releases of sequestered carbon while marine operations could have negative impacts on marine ecosystems and species (TM 2013b, Vol. 5). A BCA (Broadbent 2014) for the ENGP estimated terrestrial ecosystem goods and services losses to be in the range of $8 to $707 million net present value (2012 $), indicating that EGS losses from pipeline construction alone can be significant. We do not provide an estimate of EGS damage costs for the TMEP due to data limitations and thus our environmental damage cost estimates may underestimate the total costs of the TMEP.

5.9. Other Costs

In Appendix A we list 162 negative impacts associated with the TMEP only a few of which are monetized into our CBA results. We did not attempt to "monetize" most of these impacts into dollar amounts due to data limitations and methodological challenges in estimating the costs. Many of these impacts result from construction activities that can create social and economic problems such as increased prices for necessities (e.g., housing), increased social problems such as drug use and crime, and other problems caused by the influx of large transitory construction work forces into smaller communities. There are also many biophysical impacts, only several of which we have been able to estimate monetary damages for to include in our CBA (air pollution and GHG emissions).

It is important to emphasize that these non-monetized costs need to be taken into consideration in the TMEP evaluation even though they are not directly incorporated into the BCA. Our monetary estimates therefore underestimate the costs of the TMEP due to omission of these other adverse impacts. We discuss several important impacts of this nature below.

5.9.1. Impacts on First Nations from Oil Spills

The importance of environmental valuation for First Nations was recently demonstrated by the decision of the Lax Kw'alaams First Nation in the Prince Rupert area of the North Coast who rejected an offer of over $1.1 billion in cash payments and land by the terminal and pipeline proponents of the Pacific Northwest LNG project and the BC government for the Nation’s agreement to develop the project (Lax Kw'alaams Band 2014). This amounts to an undiscounted $308,000 per member of the First Nation.[27] The Nation rejected the offer on the grounds that the project would unacceptably affect salmon habitat with environmental and cultural implications. As the Lax Kw’alaams First Nation stated:

> *[h]opefully, the public will recognize the unanimous consensus in communities (and where unanimity is the exception) against a project where those communities are offered in excess of a billion dollars, sends an unequivocal message this is not a money issue: this is environmental and cultural (Lax Kw'alaams Band 2015, 2)*

No assessment has been made of the monetary value of the risk posed by TMEP to First Nations, but the decision by the Lax Kw'alaams First Nation to reject an offer of $1.1 billion for an LNG project that has no oil tanker spill risk illustrates that the valuation of potential environmental costs for a project that has a risk of oil spills such as the TMEP would be very high.

Oil spills can be particularly devastating to First Nations. Oil spills can result in reductions in subsistence harvest that can have potentially significant socio-cultural impact on Aboriginal people. The traditional lifestyle and culture of First Nations depends on food resources within the project area of the proposed TMEP. Marine resources harvested from traditional territories provide food, medicine, fuels, building materials, and resources for ceremonial and spiritual purposes. Fishing for food, social, and ceremonial purposes is a defining cultural practice of the traditional

[27] According to the federal government, the Lax Kw’alaams First Nation has a total registered population of 3,733 (AANDC Undated). The undiscounted total benefits package amounts to $1,149,983,183 (Lax Kw'alaams Band 2014). If the benefits package is discounted at 8%, the total package amounts to a net present value of approximately $374 million, or $100,206 per member.

lifestyle of First Nations that has preserved close relationships throughout their territories and sustained the social structure of their communities.

It is difficult to monetize costs associated with losses from reduced subsistence harvest. However, research on the impacts of the EVOS spill on Aboriginals shows that the costs can be significant. The EVOS caused long-term adverse impacts to the economic, cultural, and social infrastructure provided by traditional subsistence harvests (Fall et al. 2001). Subsistence harvests were negatively impacted by real and perceived contamination of resources and concerns over current and future scarcities of wild foods (Fall et al. 2001), and the influx of people following the spill (Miraglia 2002). These disruptions coincide with an average 50% reduction in the production of wild food volumes in spill-affected communities (Fall et al. 2001). When subsistence harvests eventually returned to near pre-spill levels 14 years after the EVOS, there was a change in the composition of harvests with a reduction in the proportion of marine mammals relative to fish due to the reduced number of marine mammals and the perception that mammals were contaminated and unsafe to eat (Fall et al. 2001).

Another cost of the EVOS was psychological stress caused by the disruption of traditional and cultural practices. Palinkas et al. (1993) found that exposure to the EVOS was significantly associated with the post-spill prevalence of generalized anxiety disorder, and an increase in drinking, drug abuse, and domestic violence. Further, Alaska Natives perceive long-term cultural effects including impairment of intergenerational knowledge transfer (Fall 2006). The EVOS disrupted opportunities for young people to learn about cultural practices and techniques, and almost three-quarters (72%) of Alaskan Natives stated that their traditional way of life had not recovered from the effects of the oil spill (Fall 2006).

The resolution of compensation issues from spill damage also imposed large costs on impacted parties. Difficulties and uncertainties in resolving compensation issues are exemplified by the drawn out, 20-year court case seeking punitive damages against Exxon in the aftermath of the EVOS. Alaska Natives impacted by the EVOS were particularly exposed to the uncertainties and stressors of ongoing litigation (Fall et al. 2001). As Picou et al. (2009) conclude:

> *[t]hese findings reveal that litigation resulting from the EVOS has perpetuated negative community and individual impacts for over a decade. As such, litigation functions as a "secondary disaster" that denies community recovery by fostering a necessary adversarial discourse that divides and fragments communities long after the original technological catastrophe. This legal discourse results in repeated reminders of the original event and victims continue to be economically impacted, disrupted and stressed by court procedures and appeals that appear unfair and irrelevant to the original damage claims (p. 306-07).*

5.9.2. Conflict and Opposition

Another potential social cost that is difficult to value monetarily is the cost of major conflict over the building of the TMEP as a result of opposition to the project. Polls show strong opposition to major pipeline projects in BC (e.g., Justason Market Intelligence 2013). Many interveners including the City of Vancouver and City of Burnaby and some First Nations are opposed to the TMEP and there have already been some demonstrations against the TMEP. The ongoing legal and political conflict over the ENGP is indicative of the types of legal and other costs associated with attempting to develop projects that may lack "social license". Trying to build a major project in such a conflicted environment may result in significant costs in the form of both direct costs associated with resolving disputes and indirect costs resulting from impairment of Canada's international reputation and business environment. For example, in its most recent annual report, Enbridge (2015, p.113) identifies opposition to its projects as a significant business risk affecting Enbridge's reputation. Although none of these potential costs are included as monetary values in our BCA, the costs could be significant.

5.10. Benefit Cost Analysis Results

Our multiple account BCA results are summarized in Table 16 and Table 17. The results of the BCA for the base case (Table 16) show that the TMEP will result in a **net cost** to Canada of $6.5 billion net present value. A large component of the cost is the cost of unused capacity costs of $3.1 billion, which will be borne by the oil transportation sector, oil producers, and the Canadian public in the form of reduced tax and royalty revenue.[28] The significance of unused capacity costs is not surprising given that the TMEP is forecast by TM to contribute to unused capacity in the Canadian oil transportation sector beyond the 2037 forecast period if all proposed projects are built. This estimate of unused capacity costs is also conservative because it omits potential lost revenues on the US portion of Canadian pipelines. Tax revenue benefits in the base case are minimal because most of the tax revenue to government is offset by costs to government and/or is replaced by taxes generated in alternative economic activity if TMEP is not built. Environmental costs are also significant, comprising $289 million for GHG emissions, $85 million for other air pollution, $1 billion for oil spills, and an additional $2 billion for passive use damages. These base

[28] The precise distribution of unused capacity costs is difficult to determine because it depends on many factors including the degree to which the costs result in higher transportation tolls that reduce netbacks to oil producers and reduce tax and royalty payments to governments.

case environmental damage estimates are conservative because they are based on WTP and not WTA for passive use damages and they exclude many adverse impacts for which we are unable to estimate monetary costs.

The results of our sensitivity analyses (Table 17) show that the TMEP has a **net cost** to Canada under all scenarios, ranging between costs of $4.1 billion and $22.1 billion. The highest net cost is based on assuming WTA for passive use values, which increases the net cost estimate by $15.6 billion. Fewer new projects and higher oil production reduce the net costs while more projects, lower oil production and higher environmental impacts increase the net costs. The lowest net cost ($4.1 billion) is based on the assumption that Keystone XL and Energy East are not built. The price lift scenario that assumes higher netbacks to producers from the TMEP reduces the net cost by about $2 billion but it is insufficient to compensate for the costs of unused capacity and unlikely to occur. In sum, there is no scenario in which the TMEP results in a net benefit to Canada.

An obvious question is if the TMEP results in a net cost to Canada, why would it be built? The explanation would seem to be based on the existence of market failures. TM could earn a reasonable return on the TMEP because it has contracts negotiated during a period of more optimistic expectations of oil development that obligate shippers to pay tolls that could financially justify TM's investment. The costs, however, are externalized onto other parties in the form of unused capacity costs and environmental and other externalities. Therefore, it may be financially feasible for TM to build TMEP even though it imposes a net cost to Canada.

We also note that the CBA results for the TMEP are very much a function of the fact that the TMEP will contribute to excess transportation capacity and the supposition that the TMEP will have little to no impact on oil production in the WCSB. If and when the oil transportation system nears full capacity, decisions on new capacity will affect WCSB production. In this case, a benefit cost analysis of new transportation projects would have to include the full social costs and benefits of incremental oil production resulting from the availability of new transportation capacity, including factors such as resource rent benefits and environmental costs of upstream production such as GHG emissions. We have not conducted an evaluation of these upstream costs and benefits in our BCA because they are not relevant given the forecast of excess capacity.

Table 16. Benefit Cost Analysis Results for TMEP

Item	Net Benefit (Cost), Base Case (million $)	Sensitivity Analysis Range (million $)[1]
TMEP Pipeline Operations	0	(792) to 396
Unused Oil Transportation Capacity	(3,098)	(13,338) to (2,112)
Oil Price Netback Increase	0	0 to 2,008
Employment	77	77 to 284
Tax Revenue	242	242-892
Electricity	(257)	No sensitivity
GHG Emissions from Construction and Operation of TMEP and marine traffic in defined study area	(289)	(916) to (289)
Other Air Emissions	(85)	(427) to (9)
Oil Spills	(1,022)	(1,022) to (310)
Passive Use Damages from Oil Spill	(2,026)	(17,667) to (2,026)
Other Socio Economic, Environmental Costs not estimated	See Appendix A	
Base Case Net Cost	**(6,458)**	**(4,070) to (22,099)**

Note. 1. Based on sensitivity scenarios

Table 17. TMEP BCA Sensitivity Analysis Results

Scenario	Description	Net Benefit/ (Cost) (million $)
Base Case		(6,458)
Higher Unused Capacity Cost	Diverted shipments from Cushing	(11,378)
Lower Unused Capacity Cost	50% Rail and 50% Pipeline	(5,472)
Unused Capacity Cost based on TMEP capital cost approach		(6,567)

Scenario	Description	Net Benefit/ (Cost) (million $)
Higher Oil Production	TM/IHS 2013 base	(5,981)
Lower Oil Production	TM/IHS 2013 low	(6,989)
Higher Transport Capacity	Include NGP and lower Bakken shipments on Keystone XL and Energy East	(6,796)
Lower Rail Transport Capacity	Reduce rail capacity to current level (300 kbpd)	(6,196)
Lower Pipeline and Rail Capacity	Reduce rail capacity to current level (300 kbpd) and no Keystone	(5,443)
Lower Pipeline and Rail Capacity	Reduce rail capacity to current level (300 kbpd), no Keystone and no Energy East	(4,070)
IHS Capacity Assumptions (no rail)		(6,287)
Oil Price Uplift	IHS estimate of Asian uplift	(4,450)
Higher Employment Benefit	15% of Construction & Operating employment	(6,251)
Higher Tax Revenue	Property tax + Asian uplift taxes and royalties (IHS 2015 estimate)	(5,808)
Higher GHG Emission Damage Cost	Higher damage costs per unit	(7,084)
Higher Air Pollution costs	Higher Damage Cost per Unit	(6,800)
Lower Air Pollution Costs	Lower Damage Cost per Unit and assumed mitigation	(6,379)
Higher Passive Values	WTA for Canadian	(22,099)

Scenario	Description	Net Benefit/ (Cost) (million $)
	households	
Lower Oil Spill Costs	TM probability for Tanker spills (90 year return period)	(5,747)
Higher Discount Rate (10%)		(5,592)
Lower Discount Rate (5%)		(8,360)
Lower Discount Rate (3%)		(10,268)

5.11. Risk Assessment and Uncertainty

As our sensitivity analysis illustrates, different assumptions result in different estimates of the net impacts of the TMEP. In project evaluation it is important to assess the uncertainties underlying these assumptions used in the evaluation and their implications on the net impacts of the project.

One principal variable impacting our BCA results is the cost of unused oil transportation capacity. This variable is in turn shaped by three variables – oil supply, transportation capacity, and the costs per barrel of unused capacity – and there is uncertainty in forecasting each one of these variables. As the recent downward revision of oil supply forecasts indicate, forecasting future oil production is uncertain. Higher oil supply forecasts will reduce unused capacity while lower oil supply forecasts will increase unused capacity. We have addressed this uncertainty by using a range of WCSB oil export forecasts provided by TM in our sensitivity analysis. The results show that under all the oil supply scenarios tested there is still a large unused capacity cost (Table 16). Also, given the lag in adjustment of forecasts to recent price declines, it is likely that current forecasts may be too optimistic.

The second variable impacting our estimate of unused capacity costs is the magnitude of existing and proposed transportation projects. Our assumptions regarding development of transportation projects are consistent with those provided by TM, although we assume a slightly different mix of projects with more rail and less pipeline capacity (Table 7). Both our and TM's transportation capacity forecasts assume completion of new projects including Keystone XL, Enbridge mainline expansions, and Energy East.[29] There is uncertainty whether all of these projects will be built by the anticipated completion dates and capacity may therefore be lower than forecast, resulting in lower unused capacity estimates. We have addressed this uncertainty by using lower capacity scenarios, and under all scenarios there are substantial unused capacity costs.

We acknowledge that it is possible that transportation capacity could become constrained at some point in the future if oil production is significantly higher than forecast and/or new transportation facilities are not built as planned. As illustrated in Figure 2, some new transportation capacity will be required in the next decade even under lower oil production growth assumptions. However, if there is higher than forecast production and lower than forecast capacity additions, there should be sufficient lead time to assess and accommodate these unanticipated changes to avoid any shutting in of production.[30] If, on the other hand, unneeded expensive pipeline facilities are built, the costs of the unused capacity are fixed and will impose long-term costs on the oil and gas sector, as well as costs to government in the form of lower tax revenue. For these reasons it is more advisable to avoid expensive, irreversible investments in pipelines that cannot be justified by demand.

The third variable impacting our estimate of unused oil transportation capacity costs is the per barrel cost of unused capacity. The costs of unused capacity depend on how much and where the oil is diverted from to be shipped on the TMEP. Our analysis assumes that the oil shipped on TMEP would most likely be diverted from Enbridge's pipeline system due Enbridge's lack of long-term contracts, but it is also likely that some diversions from other oil transportation systems may occur. Further, the destination point for oil diverted from Enbridge is also unknown and as our estimates show, the destination assumption has a significant impact on unused capacity cost estimates (Table 9). We have addressed uncertainty over destination points for diverted oil by using a range of unused capacity cost estimates based on different destinations and capping rail in some of the sensitivities. The sensitivity analysis shows that there are significant unused capacity costs for all of the scenarios tested. Therefore, while there is uncertainty over what transportation facilities are impacted by the diverted oil, this uncertainty does not alter the conclusion that there will be sizeable unused capacity costs.

[29] TM's forecast also assumes that ENGP will go ahead.

[30] Increases in production are preceded by increased drilling activity, giving lead time to make transportation adjustments.

Another important cost parameter in our BCA is environmental costs including the risk of oil spill damage. We acknowledge that there is uncertainty relating to oil spill probability and oil spill damage estimates that affect the accuracy of oil spill damage cost forecasts. We have addressed this uncertainty by testing different assumptions and the results vary appreciably, especially for passive use values. However, while the impact of alternative assumptions affects the magnitude of the oil spill damage estimates, there is still a high cost from oil spills under all scenarios.

We also caution that our oil spill estimates may be conservative. Oil spill costs vary with the unique characteristics of the type of spill and impacted environment. We would expect spill costs to be higher in the Georgia Strait due to its high value environment than spills in many other areas (WSP 2014). Our estimates of environmental costs and oil spill costs also omit many environmental impacts (see Appendix A). We also note the high values placed on environmental protection by the Lax Kw'alaams First Nation in its rejection of a $1.1 billion offer (just over $300,000 per person) to approve a LNG project. While there are many factors affecting this decision, the decision by the Lax Kw'alaams First Nation may indicate that current WTP estimates and WTA estimates commonly used in CBA studies, including ours, may significantly underestimate environmental protection values.

6. Conclusion

The NEB has two criteria that need to be satisfied for a project to be approved: that the project is clearly demonstrated to be needed, and that the project is clearly found to be in the public interest. TM's application states that the project is needed and in the public interest because it will provide pipeline capacity to transport increased oil production from the WCSB, it will increase netbacks for oil producers, and it will generate significant economic activity.

TM's assessment of the need for the TMEP and impact of the TMEP on public interest is deficient and incomplete in several important respects. TM's forecast of increased netbacks for all Canadian oil exports resulting from lower transportation costs is inconsistent with TM's own evidence, which forecasts a surplus of pipeline capacity with no transportation constraints. Second, TM's forecast of a permanent Asian price premium to 2037 is highly unlikely because it is inconsistent with the dynamics of world oil markets. Third, TM estimates gross instead of net impacts and incorrectly define gross economic impacts as benefits without taking into account the opportunity costs of the capital and labour that would be employed by the TMEP. Finally, TM does not provide any estimates of many of the potential economic, environmental and social, costs of the TMEP in its analysis, contrary to the requirements specified by the NEB.

To help assess the need and public interest impacts of the TMEP we completed a multiple account BCA which shows that the TMEP will result in a significant **net cost** to Canada ranging between $4.0 and $22.1 billion net present value. We tested a number of alternative scenarios and assumptions and found that under every likely scenario tested the TMEP results in a net cost to Canada. We also emphasize that our net cost estimates are conservative because we have not been able to monetarily value a large number of environmental and social costs.

Therefore, we conclude that the TMEP does not meet the NEB criteria for project approval, and approving and constructing the TMEP will result in a significant net cost to Canada. We further conclude that the current approach of evaluating proposed oil transportation projects on a case-by-case basis is deficient and that a better approach is to develop a comprehensive oil transportation strategy that assesses and compares all viable transportation options to identify the option or mix of options that meets the transportation needs of the Canadian oil sector in the most cost-effective social, environmental, and economic manner.

7. Appendices

7.1. Appendix A: Potential Impacts of the TMEP

Table 18. List of Some Potential Impacts of the TMEP Identified in Trans Mountain's Application.[31]

Type	Potential Impacts from TMEP
Heritage Resources	1. Disturbance to known and previously unidentified archaeological sites during field studies and construction 2. Disturbance to previously unidentified historic sites during field studies and construction 3. Disturbance to previously unidentified paleontological sites during construction
Traditional Land and Resource Use	4. Disruption of the use of trails and travel ways 5. Loss of habitation sites or reduced use of habitation sites 6. Alteration of plant harvesting sites 7. Disruption of subsistence hunting, fishing, and trapping activities 8. Disruption of marine subsistence activities including marine access and use patterns 9. Disturbance of gathering places and sacred areas 10. Disruption of cultural sites in the marine environment 11. Sensory disturbance during construction and

[31] This list is based on TM's application (TM 2013b, Vols. 5 and 7) and is not intended to be a comprehensive list of all potential impacts of the TMEP. Impacts normally deemed as positive impacts are italicized.

Type	Potential Impacts from TMEP
	operation (from noise, air emissions, lighting, visual)
Human Occupancy and Resource Use	12. Physical disturbance to protected areas and facilities, including trails and trailheads, within protected areas 13. Change to access of protected areas 14. Sensory disturbance of land and marine resource users (from noise, air emissions, lighting, visual) 15. Physical disturbance to First Nation Reserves, Aboriginal communities, and asserted traditional territories 16. Disruption of traditional land and marine resource use activities 17. Change to access of First Nation Reserves and asserted traditional territories 18. Physical disturbance to residential areas and community use areas 19. Changes to all agricultural land uses including effects on livestock or agricultural plants due to the introduction of pests and disease 20. Disturbance of natural pasture, grazing areas, livestock movement and grazing patterns 21. Disturbance of field crop areas and organic and specialty crop areas 22. Disruption of farm facilities and risk to livestock and plant health 23. Physical disturbance of waterways used for recreational activities, outdoor recreation trails and use areas 24. Disruption to commercial recreation tenures and outfitting, trapping, hunting, and fishing activities 25. Disturbance to managed forest areas, Old Growth Management Areas, and merchantable timber areas and production 26. Decline in forest health during construction 27. Disruption of oil and gas activities and mineral and

Type	Potential Impacts from TMEP
	aggregate extraction activities 28. Physical disturbance to industrial and commercial use areas 29. Change to access for other land and resource users during construction 30. Alteration of surface water supply and quality for downstream water users 31. Alteration of well water flow and quality for water users 32. Alteration of viewsheds 33. Disruption to Rockfish Conservation Areas and marine access to protected areas 34. Physical disturbance to marine Aboriginal traditional use areas
Community Well-being	35. Change in population and demographics during construction and operations 36. Changes in income patterns 37. Effects on community way-of-life from the presence of construction activity and temporary workers 38. Physical disturbance to community assets (e.g. schools public facilities, parks) 39. Effects on Aboriginal harvesting practices and cultural sites 40. Effects on Aboriginal culture from employment opportunities and other TMEP activities
Infrastructure and Services	41. Increased traffic from transportation of workers and supplies including traffic safety effects 42. Physical disturbance to roads due to pipeline road crossings 43. Disturbance to railway lines 44. Physical disturbance to the Merritt Airport that could restrict the ability for flights to take off and land

Type	Potential Impacts from TMEP
	45. Increased use of Port Metro Vancouver during construction and potential disruption to navigable water 46. Effects on linear infrastructure (e.g. sub-surface lines and power lines) and increased demand for power 47. Increase in water infrastructure demand including temporary increase in water demand during construction 48. Increased need for waste management during construction 49. Demand for housing during construction including upward pressure on rental price and/or short-term accommodations 50. Demand for post-secondary educational services/training 51. Demand for emergency, protective, and social services during construction 52. Use of recreational amenities by workers during construction
Employment and Economy	53. Contribution to provincial and national growth during construction and operations; 54. Employment opportunities during construction and operations 55. Reduced labour availability for other regional industries due to workers taking TMEP-related employment opportunities *56. Increased municipal tax revenue* *57. Increased personal spending by TMEP workers during construction* *58. Combined effect on municipal economies from an increase in municipal tax revenue and increased personal spending by TMEP workers during construction* *59. Increased regional contracting and procurement opportunities*

Type	Potential Impacts from TMEP
	60. *Training opportunities, particularly for Aboriginal communities for skill and capacity development* 61. Disruption to business or commercial establishments in the form of reduced income 62. Disruption to resource-based income or livelihoods
Human Health	63. Effects on mental well-being from demographic changes, changes in income, and changes to culture 64. Effects on alcohol and drug misuse 65. Increase in demand on mental health and addictions services 66. Increase in number of sexually transmitted infections 67. Increase in number of respiratory or gastrointestinal illnesses 68. Increase in stress and anxiety related to perceived contamination 69. Increase in traffic-related injury and mortality 70. Increased demand on hospitals, health care facilities, and emergency medical response services 71. Effects on diet and nutritional outcomes 72. Effects on mental well-being in Aboriginal communities
Marine Resource Use	73. Disruption to marine access and use patterns during construction and operations 74. Alteration of subsistence resources 75. Disturbance to cultural sites including sensory disturbance from noise, air emissions, lighting, and visual during construction and operations 76. Sensory disturbance for commercial, recreation, and tourism users (e.g. noise, lighting, visual, air quality) during construction and operation 77. Change in distribution and abundance of harvested species including marine fish and fish habitat

Type	Potential Impacts from TMEP
	78. Displacement of commercial, recreational and tourism users around Westridge Marine Terminal during construction and operations 79. Change in commercial, recreational and tourism vessel access routes during construction and operations 80. Disruption to subsistence hunting, fishing, and plant gathering activities 81. Disruption to use of travel ways by traditional marine resource users 82. Disturbance to gathering places including increased sensory disturbance for marine users 83. Disturbance to sacred sites 84. Disruption to commercial fishing activities 85. Sensory disturbance (e.g. noise, visual effect, air quality) for commercial fishers, recreational users, and tourism users 86. Change in distribution and abundance of target species for commercial fishers 87. Alteration of existing movement patterns of marine commercial, recreational, and tourism users 88. Increased rail bridge operations 89. Marine vessels collision with built infrastructure, marine facilities or shoreline with a commercial, recreational, or tourism use 90. Marine vessel collisions with marine commercial users, other recreational users, and marine tourism users 91. Marine vessel wake effects on small fishing vessels, recreational vessels and tourism operator vessels 92. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Accidents and Malfunctions	93. Spills of hazardous materials during construction and maintenance potentially resulting in contamination or

Type	Potential Impacts from TMEP
(terrestrial and marine)	alteration of surface or groundwater 94. Fires that may adversely affect adjacent property 95. Damage to utility lines that could interrupt services and lead to fires 96. Transportation accidents that could cause injury to people or result in a fire 97. Use of explosives that could cause injury from flying rock 98. Security risk including damage from criminal activity 99. Change in marine water quality from an accidental release of contaminated bilge water 100. Physical contact between a tanker's hull and marine subtidal habitat from vessel grounding 101. Interference with navigation from a vessel grounding 102. Physical injury or mortality of a marine mammal due to a vessel strike 103. Venting of tanker at anchor or in transit 104. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Physical Environment	105. Terrain instability due to slumping at watercourse crossings and sidehill terrain 106. Alteration of topography along steep slopes, slopes of watercourse crossings, sidehill terrain, and areas of blasting 107. Acid generation or metal leaching rock
Soil and Soil Productivity	108. Decreased topsoil/root zone material productivity during topsoil/root zone material salvaging 109. Decreased topsoil/root zone material productivity through trench instability during trenching, mixing due to shallow topsoil/root zone material, mixing due to poor colour change, and mixing with gravely lower

Type	Potential Impacts from TMEP
	subsoils 110. Decreased soil productivity resulting from changes in evaporation and transpiration rates, use of sand as bedding material, flooding of soil as a result of release of hydrostatic test water on land, disturbance (e.g., maintenance dig activities) during operations, trench subsidence, and soil diseases (i.e., clubroot disease and potato cyst nematodes) 111. Degradation of soil structure due to compaction, rutting, and pulverization of soil and sod 112. Loss of topsoil/root zone material through wind and water erosion 113. Erosion of soil as a result of release of hydrostatic test water on land 114. Loss of topsoil/root zone material from disturbance (e.g., maintenance dig activities) during operations 115. Increased stoniness in surface horizons 116. Bedrock or large rocks within trench depth 117. Disturbance of previously contaminated soil 118. Contamination of soil as a result of release of hydrostatic test water on land 119. Soil contamination due to spot spills during construction
Water Quality and Quantity	120. Instability of trench at locations with high water table 121. Suspended sediment concentrations in the water column during instream activities 122. Erosion from approach slopes 123. Inadvertent instream drilling mud release 124. Alteration or contamination of aquatic environment as a result of withdrawal and release of hydrostatic test water 125. Reduction of surface water quality due to small spill during construction or site-specific maintenance

Type	Potential Impacts from TMEP
	activities 126. Alteration of natural surface drainage patterns 127. Disruption or alteration of streamflow 128. Shallow groundwater with existing contamination encountered during trench construction 129. Areas susceptible to drilling mud release during trenchless crossing construction, sedimentation in the aquifer, and blasting effects 130. Areas with potential artesian conditions 131. Aquifers (including unconfined aquifers) or wells vulnerable to possible future contamination from a spill during construction 132. Areas susceptible to changes in groundwater flow patterns 133. Disruption of shallow groundwater in high permeable materials in proximity to rivers or watercourse crossings with fluvial materials or colluvium in the substrate 134. Disruption of groundwater flow where springs and shallow groundwater are encountered 135. Areas where dewatering may be necessary during pipeline construction activities 136. Impacts to shallow wells
Air Emissions	137. Project contribution to emissions: increase in air emissions during construction and increase in air emissions during site-specific maintenance and inspection activities 138. Dust and smoke during construction
GHG Emissions	139. Increase in CO_2e emissions 140. Changes in environmental parameters (e.g., increase in global average temperature)
Acoustic Environment	141. Changes in sound level during construction and operation

Type	Potential Impacts from TMEP
	142. Changes in vibrations during construction and operation
Fish and Fish Habitat	143. Riparian and instream habitat loss or alteration during construction, maintenance, and operation activities 144. Riparian and instream habitat loss or alteration from accidental drilling mud release 145. Contamination from spills during construction and maintenance 146. Increased access to instream habitat during operation 147. Fish mortality or injury during construction 148. Fish mortality or injury due to accidental release of hazardous materials during power line construction 149. Increased suspended sediment concentrations in the water column during instream construction or from accidental mud release 150. Increased access to fish and fish habitat during operations 151. Blockage of fish movements 152. Effects on fish species of concern 153. Loss of habitat, mortality, or injury of Burbot, Northern Pike, Walleye, Bull Trout/Dolly Varden, Chinook Salmon, Coho Salmon, Cutthroat Trout, and Rainbow Trout/Steelhead
Wetland Loss and Alteration	154. Loss or alteration of wetlands of High Functional, High-Moderate, Low-Moderate and Low Functional Condition (i.e., habitat, hydrology, biogeochemistry) 155. Contamination of wetland function (i.e., habitat, hydrology, biogeochemistry) due to a spill during construction
Vegetation	156. Loss or alteration of native vegetation, the most affected vegetation communities, grasslands in the BG BGC Zone, rare ecological communities, and rare plant and/or lichen occurrences

Type	Potential Impacts from TMEP
	157. Weed introduction and spread
Wildlife and Wildlife Habitat	158. Change in habitat, movement, and increased mortality risk of the following wildlife: Grizzly Bears, Woodland Caribou, Moose, forest furbearers, coastal riparian small mammals, bats, grassland/shrub-steppe birds, mature/old forest birds, early seral forest birds, riparian and wetland birds, Wood Warblers, Short-eared Owls, Rusty Blackbirds, Flammulated Owls, Lewis' Woodpecker, Williamson's Sapsucker, Western Screech-owl, Great Blue Heron, Spotted Owl, Bald Eagle, Common Nighthawk, Northern Goshawk, Olive-sided flycatcher, Pond-dwelling amphibians, stream-dwelling amphibians, and arid habitat snakes
Marine Sediment and Water Quality	159. Change in sediment quality during construction 160. Change in water quality during construction or operations
Marine Fish and Fish Habitat	161. Loss of marine riparian, intertidal, and subtidal habitat 162. Decrease in productive capacity of suitable habitat, injury, or mortality of Dungeness Crab 163. Decrease in productive capacity of suitable habitat, injury, or mortality of inshore Rockfish 164. Decrease in productive capacity of suitable habitat, injury, or mortality of Pacific salmon
Marine Mammals	165. Permanent or temporary auditory injury and sensory disturbance of Harbour Seals, Southern resident Killer Whale, Humpback Whale, and Stellar Sea Lion 166. Injury or mortality due to vessel strikes
Marine Birds	167. Change in habitat quality or availability, sensory disturbance, injury, or mortality of the following marine birds: Great Blue Heron, Pelagic Cormorant, Barrow's Goldeneye, Glaucous-winged gull, and Spotted Sandpiper

7.2. Appendix B: Certificates of Expert Duty

7.3. Appendix C: Resumes

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