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Evaluation of the Trans Mountain Expansion Project

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SFU is on unceded Coast Salish Territory; the traditional territories of the xʷməθkʷəy̓əm (Musqueam), Skwxwú7mesh (Squamish) and Səlílwətaʔɬ (Tsleil-Waututh) Nations

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Dr. Thomas Gunton is Full Professor and Founding Director of the Resource and Environmental Planning Program at Simon Fraser University where he teaches advanced graduate courses in resource and environmental planning and policy. He has more than 45 years of professional experience in the natural resource and environmental management field including holding the positions of Deputy Minister of Environment, Lands and Parks, Deputy Minister of Cabinet Policy Secretariat, and Deputy Minister of Finance (Treasury Board) for the Government of British Columbia. He has also held senior positions with the Government of Manitoba, including Assistant Deputy Minister of Energy and Mines where he was responsible for major natural resource project development and evaluation, Senior Economic Analyst in the Ministry of Economic Development, and Visiting Professor in resource and environmental economics at the University of Manitoba.

While working for the BC government he managed a number of major initiatives including: a new *Environmental Assessment Act*, a new *Forest Practices Code*, a forest sector strategy, a new regional land use planning process, a redesign of the regulatory and royalty system for oil and gas development (including design and implementation of the BC Oil and Gas Commission), and new air pollution regulations. He also worked as the chief negotiator for BC on a number of major resource development projects including Alcan's Kemano completion project (including finalizing an energy agreement) and design of a new oil and gas royalty system. He has been an expert witness for various regulatory agencies including the National Energy Board, the Ontario Energy Board, the Manitoba Public Utilities Commission, the BC Arbitration Panel, and the Minnesota Public Utilities Commissions providing evidence on natural resource markets and environmental impacts of major energy projects. He has published over 80 articles in refereed journals on natural resource and environmental policy and won numerous research grants competitions from national granting agencies to fund his research. For the last decade he has worked on assessing the environmental, social and economic risks and impacts of major energy projects in BC including the proposed Enbridge Northern Gateway Pipeline (ENGP) and the Trans Mountain Pipeline Expansion (Project) and appeared as an expert witness in NEB hearings on the environmental impacts, risks, and economic costs and benefits of major pipeline projects.

Dr. Chris Joseph

Dr. Chris Joseph is principal of Swift Creek Consulting, based in Squamish, BC. Swift Creek Consulting was established in 2016 and consults on environmental assessment, economic, major project, and cumulative effects issues and provides facilitation and instruction services. Dr. Joseph has over 15 years of professional experience in the environmental consulting field with the majority of this experience concerning major project impact assessment issues. From 2016 to 2018 he was Senior Socio-economic Specialist at SNC Lavalin, Canada's largest engineering firm, in which he led socio-economic impact assessments of major projects, advised on and participated in engagement with Indigenous groups, and advised the federal government on a major project review. He has taught undergraduate and professional courses and workshops and provided teaching assistance in the topics of economics of the environment, environmental assessment, resource management institutions, political ecology, and occupational and environmental health. From 2010 through 2016 he was an Associate at Compass Resource Management in Vancouver providing consulting services in the topics of major project impact assessment, environmental economics, facilitation, and structured decision-making. Prior to this he consulted privately on sustainability and major project development issues, as well as worked with MKJA and CIEEDAC on energy and greenhouse gas issues.

Major clients include First Nations, and the BC, Alberta, and federal governments. He has provided expert testimony to the Joint Review Panel regarding the Teck Frontier Oil/tar sands mine; the Minnesota Public Utilities Commission regarding the Enbridge Line 3 Replacement; the National Energy Board regarding the Enbridge Northern Gateway Project and the Kinder Morgan Trans Mountain Expansion Project, and the Stk'emlupsemc te Secwepemc First Nation's Review Panel on the Ajax copper/gold mine. In the course of his work he has examined risk issues with respect to the proposed Enbridge Northern Gateway Project, various proposed LNG projects on the north coast of BC, the proposed NaiKun offshore wind project, and proposed offshore oil and gas development on the BC coast. Dr. Joseph has published a number of peer-reviewed articles in scientific journals on aspects of environmental assessment, economic valuation, resource management policy, and greenhouse gas emission patterns. He has a PhD from the School of Resource and Environmental Management (REM) at Simon Fraser University where he won several major awards including a Social Science and Humanities Graduate Research Scholarship. He has a Master's degree Simon Fraser University in Resource Management and a B.Sc. (Honours with Distinction) in Geography from the University of Victoria.

Daniel Dale

Daniel Dale has a Master's degree from the School of Resource & Environmental Management at Simon Fraser University and a Bachelor's of Commerce degree (with Distinction) from the University of Victoria. His Master's research focused on the use of impact benefit agreements associated with contemporary resource development in Canada and in particular, with the Trans Mountain Expansion Project. His previous professional experience was in commercial finance, where he worked with many companies in BC's resource sectors.

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LIST OF ACRONYMS

AER	Alberta Energy Regulator
BC	British Columbia
BCA	benefit cost analysis
BPD	barrels per day
CAPEX	capital expenditures
CAPP	Canadian Association of Petroleum Producers
CBC	Conference Board of Canada
CCA	capital cost allowance
CDEV	Canada Development Investment Corporation
CER	Canada Energy Regulator
CIT	corporate income tax
DCF	discounted cash flow
ECONIA	economic impact analysis
ENB	Enbridge Canadian Mainline
ENGP	Enbridge Northern Gateway Project
EVOS	Exon Valdez oil spill
GDP	gross domestic product
GHG	greenhouse gas
GWh	gigawatt hour
IEA	International Energy Agency
IOPCF	International Oil Pollution Compensation Fund
KBPD	thousand barrels per day
KM	Kinder Morgan
LNG	liquid natural gas
MWh	megawatt hour
MS	Muse Stancil
NEB	National Energy Board
NEBA	National Energy Board Act
NPV	net present value
OPP	Oceans Protection Plan
OSRA	oil spill risk assessment
PBO	Parliamentary Budget Officer
PHMSA	Pipeline and Hazardous Materials Safety Administration
TM	Trans Mountain

TMC	Trans Mountain Corporation
TMEP	Trans Mountain Expansion Project
TMP	Trans Mountain Pipeline
TMPF	Trans Mountain Project Finance
USGC	US Gulf Coast
WSC	Western Canada Select
WCSB	Western Canada Sedimentary Basin
WTA	willingness to accept
WTI	West Texas Intermediate
WTP	willingness to pay
ZEV	zero emission vehicle

Executive Summary

PURPOSE

1. The purpose of this report is to provide an independent evaluation of the Government of Canada's decision to purchase Trans Mountain (TM) and build the Trans Mountain Expansion Project (TMEP). The analysis consists of two components:

   a. a financial analysis that assesses the impact of the Government of Canada's purchase of TM on the Canadian taxpayer; and

   b. a comprehensive benefit cost analysis that assesses all of the costs and benefits of TMEP to determine if TMEP will generate a net benefit to Canada and is in the public interest.

BACKGROUND

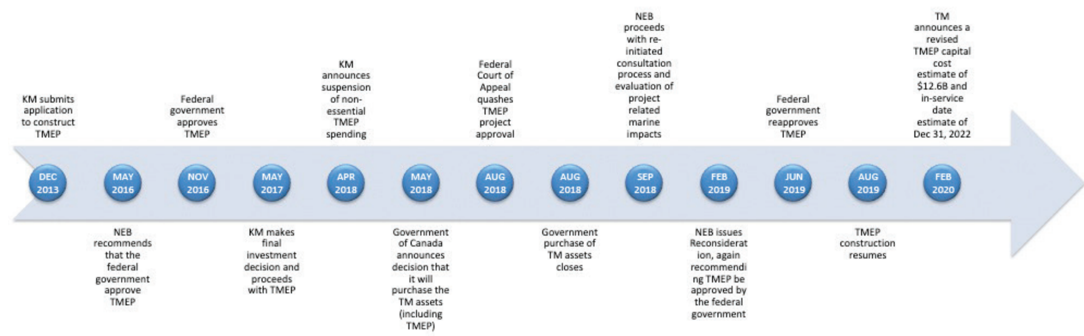
2. In May 2013 TM submitted its application to the National Energy Board (NEB) seeking approval of TMEP to twin an existing pipeline running from Edmonton, Alberta to Burnaby, British Columbia, to increase oil transportation capacity from 300kbpd to 890kbpd, and construct a marine terminal to load oil tankers to ship oil from Vancouver to Pacific Rim markets.

3. In May 2016 the NEB issued its report recommending that the federal government approve TMEP and on November 29, 2016 the federal government approved TMEP.

4. In May 2018 Kinder Morgan announced that it would halt construction of TMEP due to increasing project risks. Shortly after Kinder Morgan's announcement, the federal government announced its intention to purchase TM and the acquisition was completed in August 2018.

5. On August 30, 2018 the Federal Court of Appeal quashed the government's approval of TMEP on the grounds that there had been insufficient consultation with First Nations and

Figure ES.1 **Evolution of the Trans Mountain Expansion Project**



the NEB had not considered impacts of marine traffic in its environmental assessment. The federal government directed the NEB to conduct an additional review to address the Court's decision that marine traffic needed to be included and initiated additional consultation with First Nations.

6. In February 2019 the NEB released its reconsideration report (NEB, 2019) recommending approval of TMEP and the federal government accepted the recommendation and reapproved TMEP in June 2019. Construction resumed in August 2019 (Figure ES. 1).

DEFICIENCIES IN GOVERNMENT EVALUATION OF TMEP

7. The NEB's 2016 and 2019 evaluation of TMEP to determine whether it is justified and in the public interest contains a number of deficiencies including:

a. failure to provide a comparison of benefits and burdens in accordance with well-established principles such as benefit cost analysis that can be used to assess whether TMEP is in the public interest;

b. omission of significant potential costs associated with building TMEP (e.g., excess pipeline capacity costs, mitigation costs such as the Oceans Protection Plan, and various environmental costs);

c. unjustified conclusion that the risks of oil spills from TMEP are low and that the risk is acceptable;

d. failure to complete a comparative evaluation of alternative pipeline options;

e. failure to complete an overall supply and demand analysis for oil pipelines to determine if TMEP is needed;

f. overestimation of TMEP benefits through the use of gross economic impacts instead of net economic benefits; and

g. failure to update the economic evaluation of TMEP in its 2019 report (NEB, 2019) from its 2016 report (NEB, 2016) to take into account the significant changes that had occurred since completion of the 2016 report including weaker oil markets, rising construction costs of TMEP, and advancement of other pipeline projects that are alternatives to TMEP.

8. The Government of Canada has provided no publicly accessible evaluation of its decision to purchase TM and build TMEP. Given the magnitude of the public expenditure ($4.4 billion to purchase TM from Kinder Morgan and the currently estimated $12.6 billion cost to build TMEP), the failure to provide a public evaluation is contrary to accepted principles of public accountability.

EVALUATION OF TMEP

9. This report addresses the need to provide a publicly available evaluation of the Government of Canada's decision to purchase TM and build TMEP by providing an independent financial evaluation to assess the impact on the Canadian taxpayer and a comprehensive benefit cost evaluation to assess whether TMEP provides a net benefit to Canada and is in Canada's public interest.

10. The evaluation assesses recent developments that impact the economic viability of TMEP including:

a. advancement of alternative oil transportation projects that will add 1,640kbpd of Western Canada Sedimentary Basin (WCSB) oil export capacity, including: Enbridge Line 3 (370kbpd), other Enbridge expansions (550kbpd), Keystone (50kbpd), TMEP (590), and Rangeland (80kbpd).

b. a more than doubling of the costs of TMEP from the original estimate of $5.4 billion in 2013 to the current estimate of $12.6 billion (PBO, 2020);

c. significantly weaker oil markets due to COVID-19 and new climate change policies announced by Canada in December 2020 that lower the need for new pipeline capacity; and

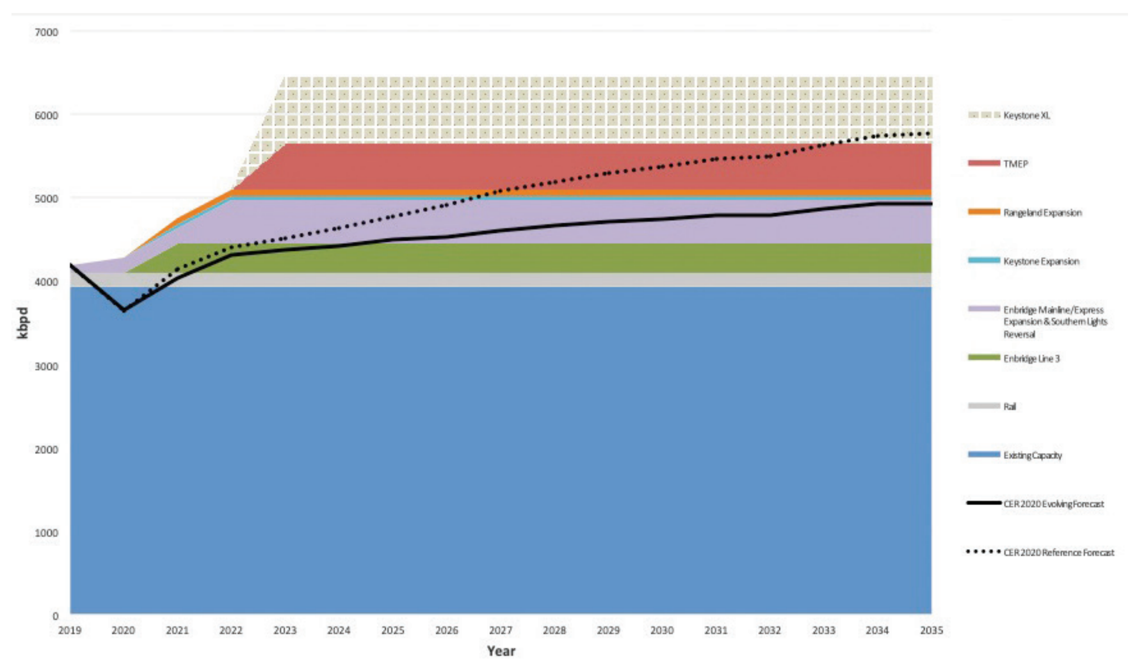
d. The cancellation of the Keystone XL pipeline by the Biden administration.

SUPPLY AND DEMAND FOR PIPELINES

11. To assess the need and economic viability of TMEP, we completed a supply and demand analysis for WCSB oil transportation services using recent estimates of current and proposed pipeline capacity and forecasts of WCSB oil exports. A number of forecasts were assessed and the two recent forecasts from the Canadian Energy Regulator (CER) are used in the analysis: the 2020 CER Evolving Scenario forecast and the 2020 CER Reference Scenario forecast.

a. The 2020 CER Evolving Scenario forecast assumes that new climate policies will continue to be implemented at the historic rate. *Under the CER Evolving Scenario*

FIGURE ES.2 Estimates of Western Canadian Oil Supply and Transportation Capacity



forecast neither TMEP nor Keystone XL are required (Figure ES. 2). If TMEP is built along with the other proposed expansions (excluding Keystone XL), there would be just over 900kbpd of excess pipeline capacity in 2030.

b. It is important to note that the CER Evolving Scenario forecast may overestimate future WCSB oil production because the climate change measures underlying the Evolving Scenario will not achieve Canada's climate change targets and are not as aggressive as the new climate plan announced by Canada in December 2020. The Evolving Scenario forecast is also higher than other forecasts such as those by the International Energy Association (IEA, 2020b). Consequently, oil production may be lower and excess pipeline capacity higher than forecast under the Evolving Scenario.

c. The second CER forecast (the Reference Scenario) assumes that no new climate policies are implemented. Given Canada's announcement of new climate policies in December 2020, the assumption of no new climate policies in the CER Reference Scenario is incorrect and the Reference Scenario forecast is therefore no longer valid. Nonetheless, we show that even under this overly optimistic forecast, the Enbridge expansions (Line 3 plus other proposed expansions) and other proposed pipeline enhancements (Rangeland, Express, and existing Keystone) will meet Western Canadian transportation needs to 2028 without building TMEP or Keystone XL. In 2028, some additional capacity may be required under this scenario.

d. Although some excess pipeline capacity is beneficial, the magnitude of excess capacity resulting from the construction of TMEP along with other proposed projects (excluding Keystone XL) will impose a significant cost on Canada's oil sector through increased tolls to cover the costs of redundant pipeline capacity and on the Canadian public through reduced tax revenues due to lower oil sector profits. The NEB did not include the costs of this excess capacity in its evaluation of TMEP costs and benefits.

TMEP FINANCIAL RISKS

12. TMEP is somewhat protected from the risks of weaker oil markets and excess pipeline capacity because it has long term contracts for 80% of its capacity. Consequently, much of the adverse impacts of excess pipeline capacity will be borne by other pipeline systems, such as Enbridge, which will lose oil shipments to meet contractual commitments on TMEP. However, weaker oil markets and the forecast excess pipeline capacity increase risks for TMEP in the following ways.

a. Securing spot shipments for the 20% of TMEP capacity not under long-term contracts will be impaired by excess pipeline capacity. Enbridge is in the process of converting 90% of its capacity to long-term contracts, which will remove about 2.7 million bpd of oil from potential spot shipments (Enbridge, 2020, p. 43). Based on Enbridge's analysis there will be very little oil that will be available for spot shipments after Enbridge converts to long-term contracts.

b. TMEP's ability to secure spot shipments will be further constrained by the escalating capital costs that will result in higher tolls that will impair TMEP's ability to compete with other lower cost pipelines such as Enbridge. The competitive position of TMEP is also impaired by the fact that oil producers will prefer to use pipelines such as Enbridge that ship directly to the US Gulf where heavy oil prices are currently higher than prices in Asia.

c. Revenue derived from the 80% contracted space on TMEP is also at risk due to the deteriorating financial position of oil producers that may impair their ability to honour their long-term contracts. Further, given the weakening of oil markets, Enbridge's shift to long-term contracts, and rising TMEP shipping costs, there is an increasing risk that shippers will not renew their long-term contracts on TMEP after they expire, thus increasing the risk of declining volumes and revenue.

13. The Parliamentary Budget Officer (PBO) completed an updated financial evaluation released in December 2020 (PBO, 2020) that concluded that the financial impact of TMEP on the federal government could range from a net gain of $2.3 billion to a net loss of $3.5 billion depending on capital costs, completion date, and shipment volumes. The PBO noted that a major risk factor is future policies to address climate change that could reduce oil production and toll revenue for TMEP. PBO estimated that stronger climate policies could result in the federal government incurring a net loss of between $0.1 billion and $3.5 billion on TMEP.

14. We conducted a financial impact analysis using a similar methodology employed by the PBO to assess the financial impacts of the purchase of TM and building of TMEP on the Canadian taxpayer. The principal difference between our analysis and the PBO analysis is that our analysis incorporates the impact of the government's climate plan that was announced December 2020 after completion of the PBO study and includes the impacts of the government's stated intention of selling TM to the private sector.

15. The results from the financial impact analysis of the Government's purchase and construction of TMEP show that TMEP will result in a net *loss* to the federal government ranging from *$2.1 to $6.9 billion* if the government follows its stated plan to sell the TM assets once TMEP is operational. There are also additional costs to government including potential corporate income tax losses due to higher depreciation charges associated with the incremental capital costs of TMEP plus an increase in government expenses generated by the Oceans Protection Plan to mitigate TMEP risks.

BENEFIT COST ANALYSIS

16. We completed a comprehensive benefit cost analysis (BCA) of TMEP consistent with Canadian BCA guidelines (TBCS, 2007) to determine if completing TMEP generates a net benefit to Canada and is in the public interest. The BCA is more comprehensive than the financial impact analysis summarized above because it includes all the costs and benefits of TMEP, not just the financial impacts on government. Two BCAs are provided: (1) A "full project" BCA that evaluates the decision to approve and build TMEP and (2) a "project completion" BCA that evaluates the net benefits of completing TMEP now that it is partially constructed. The principal difference between the two BCAs is that the project completion BCA does not include sunk costs incurred to build the project up to the end of 2020. A range of scenarios and assumptions were tested to address uncertainty in project parameters and impacts. The BCA (Table ES. 1) findings are as follows:

a. The full project BCA results show that the decision to approve and build TMEP will result in a *net cost to Canada of $11.9 billion* under base case assumptions. The net costs could range between $8.3 billion and $18.5 billion under alternative scenarios and there is no likely scenario under which TMEP would generate a net benefit for Canada even when option value benefits of access to new markets are included.

b. The project completion BCA results are relevant for determining whether there is a net benefit to Canada of completing TMEP now that it is partially constructed. The results show that continuing construction and completing TMEP will result in a *net cost to Canada of $6.8 billion* under base case assumptions and net costs could range from $3.2 billion to $13.3 billion under alternative scenarios.

c. The project completion BCA results show that Canada would be better off terminating construction of TMEP. The principal reason for this is that the oil that will be transported on TMEP could be transported on other pipelines without incurring the remaining costs of constructing TMEP. Consequently, additional spending on TMEP will not generate any incremental benefits.

d. Shelving TMEP has minimal downside risk because if demand for new transportation projects is significantly higher than forecast or other proposed pipeline expansions do

Table ES.1 Benefit Cost Analysis Results for TMEP

Item	Net Benefit (Cost), Base Case (million $)	Sensitivity Analysis Range
TMEP Pipeline Operations	(4,131)	(5,023) to (3,139)
Unused Oil Transportation Capacity	(7,401)	(7,401) to (3,796)
Option Value/Oil Price Netback Increase	0	0 to 2,293
Employment	390	390 to 585
Tax Revenue	273	273 to 1,305
Electricity	(73)	No sensitivity
GHG Emissions	(224)	(1,163) to (224)
Other Air Emissions	(110)	No sensitivity
Oil Spills	(627)	(1,412) to (55)
Passive Use Damages from Oil Spill	0	(1,953) to 0
Other Socio Economic, Environmental Costs	See Appendix 1	
Net Cost of Full Project	**(11,903)**	**(18,499) to (8,298)**
Net Cost of Project Completion (including only capital costs required to complete TMEP)	**(6,769)**	**(13,327) to (3,164)**

not proceed, there would be sufficient lead time to restart TMEP or build other projects to accommodate increased demand. Proceeding with construction of TMEP under current market conditions is high risk because once the investment is made it is a sunk cost that cannot be recovered.

17. One of the primary reasons that TMEP would result in a large net cost to Canada is because building TMEP would create excess pipeline capacity. The costs of this excess capacity will be borne by other pipeline operators whose revenues will be reduced by the reallocation of oil shipments from existing pipelines to TMEP to fulfill shipping contracts signed before the downturn in oil markets. Oil producers will also incur higher costs to cover toll increases required to finance excess capacity and governments will lose tax revenue due to lower oil company profits.

18. A second key reason that the Trans Mountain Expansion Project will result in a net cost to Canada is that the construction costs have more than doubled from $5.4 billion in 2013 to the current estimate of $12.6 billion, and costs could increase further. The tolls approved in the final cost review in 2017 were set to cover capital costs of only $7.4 billion. Therefore, the toll revenue will not be sufficient to cover the estimated $12.6 capital cost.

19. A further reason that TMEP will result in a net cost to Canada is due to the environmental risks it entails, including the risk of marine oil spills in British Columbia and greenhouse gas emissions. The probability of a marine tanker spill over a 50-year operating period for TMEP is estimated to be between 43% and 75%. The costs of a tanker spill including passive use values is estimated at $2.6 billion. The risks of a marine tanker spill would be avoided if other transportation options such as Enbridge pipeline expansions are used that do not require tanker transportation.

20. It is important to note that many environmental impacts of TMEP are not included in the quantitative benefit cost estimates because they are difficult to estimate in dollar terms. Inclusion of these environmental impacts would increase environmental cost estimates. To be consistent with the NEB's terms of reference, we have also omitted all environmental costs associated with the upstream production of oil and downstream consumption. These costs are significant and should be assessed as part of a comprehensive energy and climate change policy.

21. An alleged benefit of TMEP is that it will increase prices received by Canadian oil producers and reduce "discounting" of Canadian oil exports to the US. We evaluated this potential benefit and conclude that the analysis used by consultants (Muse Stancil) to TM to generate this benefit estimate is flawed and that is highly unlikely that TMEP will generate a price benefit. Flaws in the analysis used by TM to forecast a price benefit are as follows:

a. The analysis relies on outdated oil production and pipeline capacity forecasts that assume that if TMEP is not built, WCSB oil would have to be shipped by higher cost rail to the US Gulf. As the supply and demand analysis provided in this report shows, this assumption is incorrect.

b. The TM analysis uses a static model that does not take into account changes in refinery configurations and changes in the market destinations of oil shipments that would result from building TMEP. For example, the model incorrectly assumes that a reduction in WCSB shipments to the US market will result in a net reduction in US oil supply and an increase in oil prices received by Canadian producers. This fails to account for the fact that other oil producers would increase shipments to the US to make up for the decline in Canadian shipments thus eroding any potential price increase.

c. The assumption of higher oil prices in Asian markets is inconsistent with the functioning of world oil markets that erode price differentials between markets by redirecting shipments to higher priced markets to equilibrate prices. Price differentials may persist due to market constraints over the shorter term, but over the last decade heavy oil prices have actually been higher in the US Gulf that Asia. Consequently, using TMEP to redirect Canadian shipments from the US to Asia could result in a lower price relative to shipping to the US Gulf.

d. The flaws in TM's modeling of the alleged price benefit of TMEP are confirmed by the fact that the price discount on Canadian oil shipped to the US has actually declined over the last fifteen years despite a significant increase in Canadian shipments to the US. This directly contradicts the model forecast that higher shipments to the US result in lower prices for Canadian oil.

CONCLUSIONS

22. We conclude that:

a. The Government of Canada has not provided a public evaluation of its decision to purchase TM and build TMEP.

b. There have been significant changes since the completion of the NEB report on TMEP including emergence of new oil pipeline projects, rising TMEP construction costs, lowering of oil production forecasts, new climate change policies, and the cancellation of Keystone XL. As a result of these changes, the conclusions of the 2016 (and 2019) NEB reports are no longer valid and cannot be relied on to justify building TMEP.

c. Our financial impact analysis concludes that escalating capital costs, new climate change policies, and construction delays will negatively impact the financial viability of TMEP. The Government of Canada's purchase of TM, completion of TMEP, and eventual divestment of the pipeline system will result in a net financial loss to the federal government (and to taxpayers) between $2.1 billion and $6.9 billion.

d. Our full project BCA concludes that *the decision to approve and build TMEP will result in a net cost to Canada under base case assumptions of $11.9 billion. The net cost estimates range between $8.3 billion and $18.5 billion and there is no likely scenario in which TMEP will generate a net benefit to Canada.*

e. The project completion BCA, which assesses the benefits and cost of completing the partially built TMEP by omitting sunk costs, shows that completing construction of TMEP will result in net cost to Canada between $3.2 billion and $13.3 billion. *Therefore, continuing construction of TMEP is not in Canada's public interest and TMEP should be shelved.*

1. Introduction and Objectives

In August 2018 the Government of Canada purchased the Trans Mountain (TM) pipeline system from Kinder Morgan (KM) and announced its intent to complete the Trans Mountain Expansion Project (TMEP). The expansion project twins the existing pipeline and expands oil transportation capacity from 300,000 barrels per day (bpd) to 890,000bpd. The decision to purchase TM was made after KM announced that it was suspending work on TMEP due to increasing financial and regulatory risks.

Since the purchase of TM by the Government of Canada in August 2018, the economic viability of TMEP has been adversely impacted by market condition changes, including:

- advancement of 1,640kbpd of alternative pipeline capacity additions and upgrades, which include: Enbridge Line 3 (370kbpd), other Enbridge expansions (550kbpd), Keystone (50kbpd), Rangeland (80kbpd), and TMEP (590kbpd);
- escalation of the TMEP capital cost estimate from $5.4 billion in the original project application, to $9.3 billion at the time of the sale, to the current estimate of $12.6 billion (PBO, 2020); and
- significantly weaker oil markets due to COVID-19 and other factors such as the stronger climate change policies announced by Canada in December 2020 that lower the need for new pipeline capacity.

The Canadian government has not provided a public assessment to justify the business case for purchasing TM and proceeding with TMEP. Given the changes negatively impacting project economics and the significant financial investment of taxpayer funds, it is imperative that an evaluation be completed.

The purpose of this report is to provide an independent public evaluation of the merits of the Government of Canada's purchase of TM and decision to build TMEP. The analysis consists of two components:

- a financial analysis that assesses the impact of the Government of Canada's purchase of TM and completion of TMEP on the Canadian taxpayer; and

- a comprehensive benefit cost analysis that assesses all of the costs and benefits of TMEP to determine if under current market conditions TMEP will generate a net benefit to Canada and is in the public interest.

The major conclusions are that:

- The purchase of TM and construction of TMEP will result in a net financial cost to Canadian taxpayers of between $2.1 and $6.9 billion if the pipeline is sold after the completion of TMEP to the private sector as planned.

- Construction of TMEP will result in an overall net cost to Canada between $8.3 billion and $18.5 billion based on the full benefit cost analysis. The project completion benefit cost analysis, which assesses the benefits and cost of completing TMEP from the present onward, shows that completing TMEP will still result in a net cost to Canada between $3.2 billion and $13.3 billion. Consequently, building TMEP is not in Canada's public interest.

The report begins with an overview of TMEP and assessment of the National Energy Board (NEB) evaluation. This is followed by the financial evaluation and the benefit cost analysis.

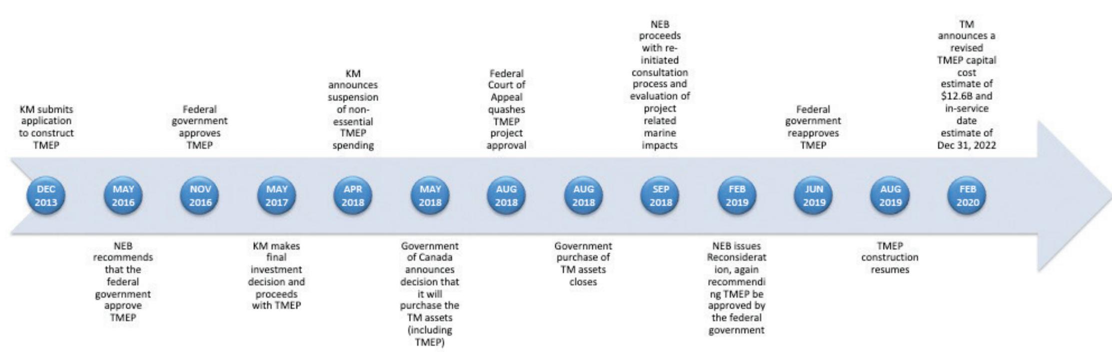
2. Trans Mountain Expansion Project Overview

PROJECT BACKGROUND

In December 2013 KM submitted its application to expand the Trans Mountain pipeline system (Figure 2.1). The objective of TMEP is to increase pipeline capacity from 300,000bpd to 890,000bpd by twinning the existing pipeline that ships oil and refined products from Alberta to British Columbia (BC) and oil to refineries in Washington State (NEB, 2019). After public hearings, the NEB recommended approval of the proposed TMEP in May 2016 and the Government of Canada accepted the NEB recommendation in November 2016.

In April 2018 KM announced that it was suspending construction of TMEP due to increasing risks and began discussions with the Government of Canada on options for supporting TMEP, which resulted in the government announcing its intention to purchase TM from KM in May 2018 (PBO, 2019). Just prior to the transfer of ownership in August 2018, the Federal Court of Appeal quashed the approval of TMEP on the grounds that there was insufficient consultation with Indigenous communities and that the marine environmental impacts of TMEP were not

FIGURE 2.1 **Evolution of the Trans Mountain Expansion Project**

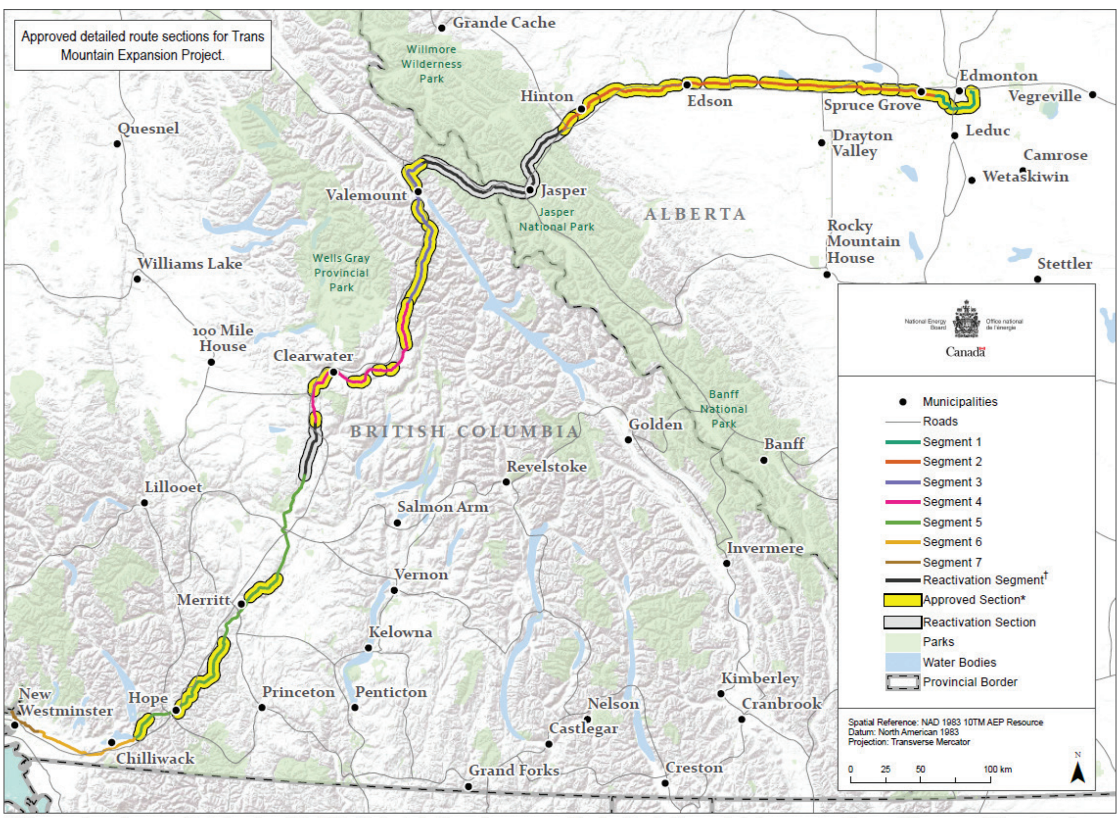


properly assessed. A second NEB hearing was initiated to address the court decision and another NEB report was released in February 2019 recommending approval (NEB, 2019). After additional consultation with Indigenous communities, the Government of Canada approved TMEP for a second time on June 18, 2019. TMEP is currently under construction with an expected completion date of December 2022 (TMC, 2020b).

PIPELINE

The proposed TMEP would twin the existing Trans Mountain Pipeline (TMP) from Edmonton, Alberta to the Westridge Marine Terminal in Burnaby, BC and increase operating capacity from the current 300kbpd of oil to 890kbpd (TM, 2013a, Vol. 2, p. 2- 12). The completed expansion would result in two pipelines. The first line (Line 1) is a 1,147-km pipeline with the capability of transporting 350kbpd (TM, 2013a, Vol. 4A p. 4A–2–3). Line 1 would use mostly existing and reactivated TMP pipe to transport refined products and light crude oils but would also have the capability to carry heavy crude oil at a reduced throughput rate (TM, 2013a, Vol. 4A

FIGURE 2.2 **Approved Route Sections for TMEP**



*This map shows the approximate location of the PPBoR sheets that have been approved by the Board. Approval of all pre-construction conditions may still be outstanding. Check the Board's website for most current information. † No PPBoR's for the reactivation segments.
Map produced by the NEB, April 2018. The map is a graphical representation intended for general informational purposes only.

SOURCE: NEB, 2018a

p. 4A–2–3). Line 2 is a 1,180 km pipeline with throughput capacity of 540kbpd for heavy crude oils but would also be capable of transporting light crude oils (TM, 2013a, Vol. 4A p. 4A-3). Line 2 would consist of approximately 987 km of newly built pipe and some existing pipe built in 1957 and 2008 (TM, 2013a, Vol. 4A p. 4A-2). The proposed route for TMEP largely parallels the existing TMP route (Figure 2.2) (TM, 2013a, Vol. 5A). TMEP would include 12 new pump stations, new storage tanks, and other new components to support Lines 1 and 2 (TM, 2013a, Vol. 4A p. 4A-3).

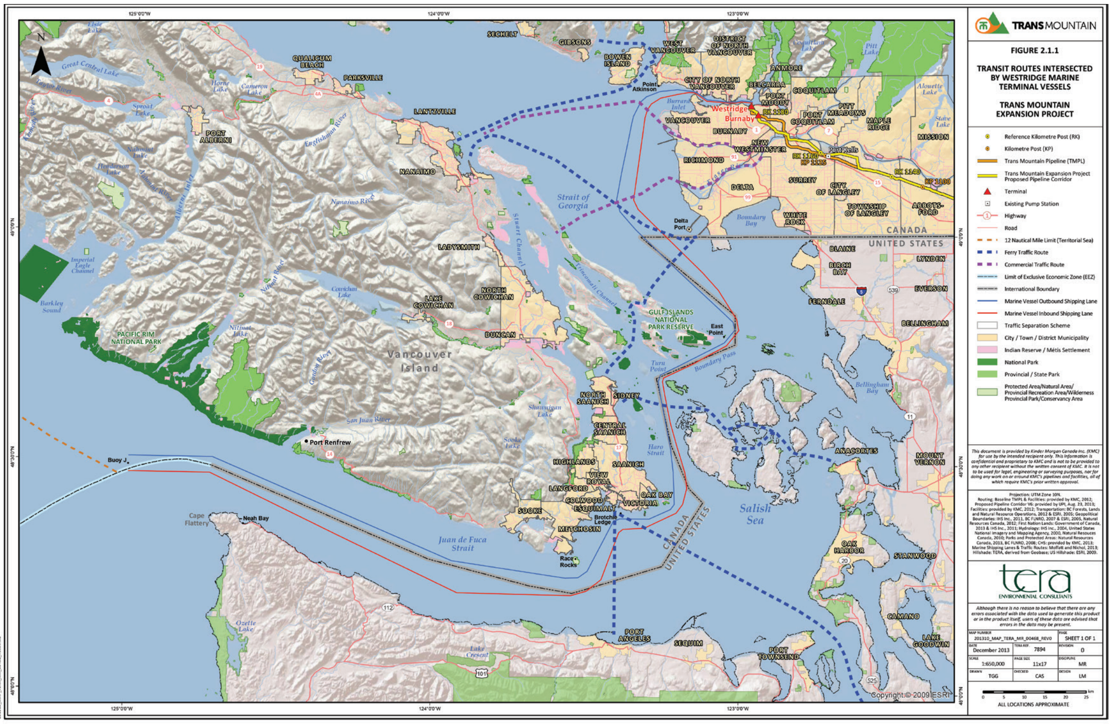
TERMINAL

TMEP includes the expansion of the 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, 2013a, 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, 2013a, TERMPOL 3.15 p. 22). Oil for tanker export would be collected and stored in new storage tanks at Burnaby Terminal and delivered to the Westridge Terminal via three delivery lines (TM, 2013a, TERMPOL 3.15 p. 22 and Vol. 4A p. 4A-3). According to TM (2013a, Vol. 2 p. 2–27), up to 630 of the 890kbpd in system capacity delivered on the TM pipeline would be for export via the marine terminal.

TANKERS

TMEP would increase tanker traffic from 60 to an estimated 408 tankers per year (TM, 2013a, Vol. 2 p. 2–27). Tankers accessing the Westridge Marine Terminal would be either 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 TMP (TM, 2013a, Vol. 8A p. 8A–68 and –71). Tankers would use tethered tugs to navigate the Vancouver Harbour Area and Georgia Straight (NEB, 2019). TM would not own or operate the tankers (TM, 2013a, Vol. 2 p. 2–27) and would not be liable to pay any costs associated with an oil tanker spill (TM, 2013a, Vol. 8A p. 8A–52). Tankers travelling to and from the Westridge Marine Terminal would use existing marine transportation routes (Figure 2.3) (TM, 2013a, Vol. 8A p. 8A–67).

Figure 2.3 **Regional Location of Marine Shipping Lanes**



Source: TM, 2013a, Vol 8A p. 8A–67

3. NEB's Assessment of TMEP

OVERVIEW

The Canadian Energy Regulator (CER), formerly the NEB, has the responsibility for approving all major interprovincial pipeline projects. TMEP was assessed under the previous *National Energy Board Act (NEBA)* and the *Canadian Environmental Assessment Act*, which were replaced in 2019 by the *Canadian Energy Regulator Act* and the *Impact Assessment Act*.

Section 52 of the previous *NEBA* (under which TMEP was assessed) states that the NEB will make a recommendation to the Minister responsible for the NEB 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 (2013a) approved the following list of issues to be considered in 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, 2013b);
- 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;
- 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 (2013a) did not 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 evaluation of TMEP. In May 2016 the NEB (2016) issued its report recommending that the federal government approve TMEP on the grounds that TMEP is needed and in Canada's public interest.

On November 29, 2016 the Governor in Council issued an Order in Council accepting the Board's recommendation and directed the Board to issue a Certificate of Public Convenience and Necessity approving the construction and operation of TMEP, subject to the conditions recommended by the Board. On August 30, 2018 the Federal Court of Appeal quashed the Governor in Council's Order approving the project and the federal government directed the NEB to conduct an additional review to address the Court's decision that marine traffic should not have been omitted from the NEB's environmental assessment review and that additional consultation with First Nations is required (NEB, 2018b). In February 2019 the NEB released its reconsideration (NEB, 2019) report recommending the approval of TMEP. The new report concluded that TMEP is likely to cause significant adverse effects, but these adverse effects would be justified by the economic benefits of TMEP. The 2019 NEB report did not consider any new information on TMEP economics despite significant changes in oil markets, increased TMEP costs, and approval of alternate pipelines that weakened the justification for TMEP.

Table 3.1 **NEB Assessment of Benefits and Burdens of TMEP**

Benefits	Rating	Burdens	Rating
Market Diversification	Considerable Regional and National	**Adverse Effect on Southern Killer Whales**	Considerable Local, Regional and National
Jobs	Considerable Local, Regional and National	**Adverse Effect on Aboriginal Culture**	Considerable Local and Regional
Competition among Pipelines	Considerable Regional and National	**Marine GHG Emissions**	Considerable Regional and National
Spending on Pipeline Materials	Considerable Local and Regional	**Municipal Development Plans**	Modest Local
Community Benefit Program	Modest Local and Regional	**Impairment of Aboriginal Use of Land and Water**	Modest Local
Enhanced Marine Spill Response	Modest Local and Regional	**Impairment of Stakeholders Use of Land and Water**	Modest Local and Regional
Capacity Development (Humans resources)	Modest Local and Regional	**Pipeline Oil Spill**	Acceptable Risk Local and Regional
Government Revenue	Considerable Local, Regional and National	**Marine Tanker Spill**	Acceptable Risk Local and Regional

Source: NEB (2016, pp. xiii–xiv).

DEFICIENCIES IN THE NEB EVALUATION OF TMEP

OVERVIEW

In its 2016 and 2019 reports, the NEB concluded that TMEP would be in the public interest.[1] In making this determination, the NEB listed what it considered to be the benefits and burdens of TMEP and concluded that the benefits exceeded the burdens in large part because the benefits would be national in scope while the burdens would be regional and local (Table 3.1). In this section of the report we evaluate the NEB's rationale for determining that TMEP is in the public interest and identify deficiencies and omissions in the NEB's analysis.

DEFICIENT COMPARISON OF BENEFITS AND BURDENS

The NEB (2016, p. 17) stated that it found "[t]his task of balancing the benefits versus the burdens of the Project was a difficult one." The NEB's method for addressing this challenge was to compare benefits and burdens by ranking them on a qualitative scale based on the magnitude and geographic scope of the impact (Table 3.1). Two ratings were applied to the magnitude of the effect (modest and considerable) and three ratings were used for the geographic scope of the effect (local, regional, and/or national). The NEB did not provide any definition of "modest"

1 The 2019 NEB report contains the same economic and public interest analysis as the 2016 report, so the critiques are applicable to both reports.

or "considerable" or any transparent method for how it determined whether an effect was modest or considerable. For pipeline spills, the NEB deviated from their effect rating system and classified pipeline spills as "acceptable risk". Again, no definition was provided for "acceptable risk" and no data was provided to determine the level of risk. No definitions were provided for "local", "regional", or "national" effects and no transparent method was used to make the spatial determinations. In "balancing the benefits versus the burdens" the NEB placed considerable weight on the economic impacts and the fact that most of the benefits would be national in scope while the burdens would be local. Based on this assessment, the NEB concluded that TMEP would be in the public interest.

A fundamental problem with the NEB's comparison of benefits and burdens is that it is impossible to understand, verify, or replicate the NEB's ratings of each benefit and burden due to the lack of definitions and transparent methods for determining the respective ratings. For example, why are jobs considered "considerable" and "national" in scope when the NEB concludes that permanent direct operating employment is 443 jobs, which is equivalent to only 0.13 % of the employment gain in Canada in 2017 (StatsCan, 2018), and this direct employment growth occurs in just two provinces (Alberta and BC)? Without a transparent method it is not possible to know the logic for these determinations. Further, how are the ratings compared to determine if the benefits exceed the burdens? For example, how does the NEB compare two "modest" burdens against one "considerable" benefit or compare the "considerable" burden of adverse impacts on killer whales to the "considerable" benefit of 443 jobs? Again, the NEB does not use any transparent method for comparison, other than to assume that a benefit or burden that is national in scope is more important than one that is regional or local. The NEB provides no justification for giving more weight to a benefit that is national versus one that is regional, and we cannot find any justification in NEB guidelines or in the project evaluation literature to justify such a weighting. The only justification for weighting benefits and costs we can find in the project evaluation literature is on the basis of equity (e.g., Shaffer, 2010), which provides higher weighting of benefits to disadvantaged groups than benefits accruing to well off segments of the population. By providing no transparent scaling, it is not possible for the NEB to compare benefits and burdens in any coherent or systematic way and the NEB conclusion that TMEP is in the public interest is therefore arbitrary and subjective.

It is hard to understand why the NEB used arbitrary, subjective judgments to compare benefits and costs when there are more comprehensive and transparent methods such as benefit cost analysis and multiple accounts analysis that the NEB could have employed to make these comparisons. These more sophisticated methods are well developed, transparent, based on sound theoretical foundations, and have been used for decades to compare project costs and benefits to determine whether a project will generate a net benefit.

NO ASSESSMENT OF ALTERNATIVE PROJECTS

The NEB *Filing Manual* (NEB, 2013b, p. 4–3) requires proponents to describe other economically feasible alternatives to the proposed project and to provide a rationale for choosing the proposed project over alternatives. According to the NEB (2013b, p. 4–4), the proponent must evaluate feasible project alternatives that meet the objective of the proposed 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, 2013b, 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, 2013b, p. 4–3).

The TMEP application (TM, 2013a) considered different pipeline corridors and alternative pump station locations in its environmental and socio-economic assessment in *Volume 5A* and *Volume 5B* and used some of the criteria referenced by the NEB (2013b) to evaluate alternatives. However, the TMEP application did not include an analysis of project alternatives that would meet the primary stated purpose of 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, 2013a, Vol. 1 p. 1–4) and the more general objective of transporting Alberta crude to world-priced oil markets other than by rail, as assessed by Muse Stancil (MS) (2015).

Consequently, the NEB did not compare TMEP to any alternatives that could meet the same objectives as TMEP and hence did not assess whether TMEP was superior from an economic, social, and environmental perspective to other transportation options. Instead, the NEB evaluated TMEP as a single stand-alone project in isolation from the alternatives.

As indicated by our supply demand analysis in this report (see section 4.3), there are several alternative transportation projects that should have been assessed relative to TMEP to identify which option or combination of options is most cost-effective from an economic, environmental, and social perspective. There are also alternative designs and routes for TMEP that could significantly reduce adverse effects and could reduce and even eliminate all tanker traffic in the Salish Sea, such as rerouting the expansion to serve oil refineries in Washington State (Ensys, 2018), that were never considered by the NEB. It is important to note that consideration of pipeline alternatives is a standard component of project evaluation in other jurisdictions. For example, the US government's assessment of pipeline proposals includes comprehensive methodology for evaluating alternatives that should be used by Canadian regulatory authorities (USDS, 2014).[2]

FAILURE TO ASSESS PROJECT NEED BY SUPPLY/DEMAND ANALYSIS

A key criterion for project review under the *NEBA* is the need for the project. Neither the project proponent nor the NEB provided a comprehensive assessment of the demand and supply of oil transportation capacity to assess the need for TMEP. Information from a study provided by the project proponent (MS, 2015) purported to show that shippers would use TMEP, but the analysis omitted key proposed pipeline capacity additions (e.g., Enbridge mainline expansions) and therefore did not provide an accurate assessment of the supply and demand for pipeline capacity. In addition to not providing an accurate supply and demand analysis to assess the need for TMEP, the MS study contained a number of other methodological errors and deficiencies that are discussed in Appendix 2. The NEB relied on this deficient analysis by MS and the fact that TM had commercial contracts with shippers to conclude that TMEP was needed. The problem

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2 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 reviewed ten alternative scenarios for shipping WCSB oil to the USGC using comprehensive economic, social, and environmental criteria.

with the NEB's analysis is that by not completing an overall supply and demand assessment, the NEB did not assess the impacts of building TMEP on the utilization of the overall oil transportation system and the market risks adversely impacting TM's shipping contracts and spot shipments. As discussed below, this resulted in the NEB not identifying the adverse impacts of TMEP on other pipelines.

OMISSIONS OF PROJECT BURDENS

Another major deficiency in the NEB analysis of the public interest is that the NEB omitted important "burdens" in its assessment of the benefits and burdens of TMEP. One significant burden omitted by the NEB is the cost of excess pipeline capacity. The cost of surplus pipeline capacity has been identified as a concern in previous NEB pipeline hearings including the Enbridge Northern Gateway Project (ENGP) hearings that reference potential costs of unused capacity of $857 million (Wright Mansell, 2012, p. 144), and the Keystone XL hearings in which the NEB reference unused capacity costs of $315–515 million per year, which would result in increased tolls for shippers (NEB, 2010b, p. 24). The NEB had evidence in the TMEP hearings that building TMEP could result in significant excess pipeline capacity costs as producers redirected their oil shipments from existing pipelines such as the Enbridge system to fulfill their contractual obligations on TMEP. The NEB acknowledged the potential for excess pipeline costs in the TMEP hearing but concluded that "… there is no reliable evidence before it demonstrating that any excess capacity would be unmanageable by sophisticated industry parties" (NEB, 2016, p. 311). Even if the NEB's unsubstantiated conclusion that the costs of excess capacity were not significant, the NEB should still have listed the potential costs of excess pipeline capacity as a burden in its evaluation.

The NEB also omitted consideration of many of the environmental and social costs of the project. In its application, TM identified 160 potential adverse effects of TMEP (see Appendix 1). While some of these are included in the NEB's burdens under the categories of impairment of use by First Nations and stakeholders, many of the adverse environmental and social costs are not listed or considered in the NEB's assessment.

INACCURATE ASSESSMENT OF PROJECT BENEFITS AND BURDENS

The NEB lists jobs, spending on pipeline materials, and government revenue as "considerable" benefits of TMEP (Table 3.1). The NEB's assessment is based on an economic impact analysis (EconIA) completed for TM by the Conference Board of Canada (CBC) (2015). The NEB's interpretation of the CBC analysis of economic benefits is incorrect. The CBC estimated the *gross* economic impacts of TMEP, not *net* effects, and it is the net effects, not the gross effects, that measure potential net benefits of the project (Grady and Muller, 1988; Shaffer, 2010; Joseph et al., 2020; Joseph, Gunton and Hoffel, 2020). For example, if TMEP created 443 operating jobs and those employed by TMEP would have been employed at the same wages on other projects if TMEP was not built, the *gross* impact is 443 jobs, but the *net* benefit is *zero* because there is no increase in total employment. Therefore, it is incorrect for the NEB to list *gross* job creation as a "considerable" benefit of TMEP when it should have used *net* job creation as the measure of benefit.

To analyze net job creation, one must assess how other firms and industries are affected by TMEP 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, interest and exchange rates. To estimate 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; Joseph et al., 2020; Joseph, Gunton and Hoffel, 2020).

The NEB's interpretation of the CBC's estimates of government fiscal benefits is also incorrect. Again, the CBC estimates *gross* government revenue, not *net* revenue, and it is the net revenue that measures the benefit. The gross government revenue estimate for TMEP construction and operation is based on the assumption that all the labour and capital employed by TMEP would otherwise be unemployed and would not therefore generate any tax revenue absent TMEP. In a well-functioning economy, most and possibly all of this labour and capital would be otherwise employed over the TMEP operating life and would generate tax revenue in alternative employment. Another deficiency in the CBC's EconIA is that it does not include potential incremental fiscal costs on government induced by TMEP such as emergency response to clean up oil spills and regulatory oversight. For example, the federal government has announced its plans to spend $1.5 billion on ocean protection to partially mitigate adverse impacts from TMEP tanker traffic (ECCC, 2018). None of these costs are deducted from the gross revenue estimates. The gross revenue estimates also include the revenue generated by an alleged price lift for Canadian oil exports attributed to TMEP. As discussed in Appendix 2, the data and methods used to forecast this price lift are flawed and given the construction of other proposed pipelines and the increased costs to complete TMEP, a price lift is highly unlikely to occur.

The NEB's assessment of risks of oil spills from TMEP is also deficient. The NEB (2016) concluded that large and credible worst-case marine tanker and terminal oil spills and credible worst-case pipeline spills from TMEP would have significant adverse effects, but that large spills would be unlikely to occur and therefore the risk would be acceptable. The deficiencies in the NEB's risk analysis are that it:

- did not refer to any quantitative spill probability estimates to justify the conclusions that large spills would be unlikely;
- did not provide any definition of large and small spills;
- failed to determine whether small spills could cause significant adverse effect; and
- provided no estimate of the costs of a credible worst-case marine spill and consequently did not assess the adequacy of financial capacity to cover the costs of a credible worst-case marine spill.

Evidence given before the NEB (Gunton and Broadbent, 2015) documented that the risk of oil spills was high and that smaller spills could generate significant adverse effects. Evidence given before the NEB Reconsideration Hearing documented that the NEB analysis of the risks of spills is deficient (Gunton and Joseph, 2018).

SUMMARY OF DEFICIENCIES IN THE NEB ASSESSMENT OF PUBLIC INTEREST

In sum, the NEB's assessment of whether TMEP is needed and is in Canada's public interest has the following deficiencies:

a. failure to provide any comparison of TMEP benefits and burdens in accordance with well-established principles and guidelines such as benefit cost analysis;

b. inaccurate characterization of benefits and burdens as national, regional, and local and incorrect assumption that regional or local costs and benefits should be discounted relative to benefits deemed national;

c. omission of significant potential costs associated with building TMEP (e.g., excess pipeline capacity and various environmental costs);

d. unjustified conclusion that the risks of oil spills from TMEP are low and that the risk is acceptable;

e. incorrect assumption that TMEP may increase Canadian oil prices;

f. failure to complete any comparative evaluation of social, economic, and environmental costs and benefits of alternative pipeline options to determine if TMEP is superior to other options from a public interest perspective;

g. failure to complete an overall supply and demand analysis for oil pipelines to determine if TMEP is needed;

h. overestimation of TMEP benefits through the use of gross economic impacts as a measure of benefits instead of net impacts and net economic benefits. (For example, the NEB identifies that a benefit of the TMEP's operation is the creation of 443 jobs, while ignoring the fact that net job creation is much smaller because these jobs would be created by other projects that would proceed if TMEP is not built);

i. overestimation of TMEP revenue benefits by using gross revenue estimates that omit incremental costs to government such as the $1.5 billion federal Oceans Protection Plan and omit government revenue that would be generated by other projects that would proceed if TMEP is not built; and

j. failure to update the economic evaluation of TMEP in its 2019 report (NEB, 2019) from its 2016 report (NEB, 2016) to take into account the significant changes that occurred since completion of the 2016 report including the weakening of oil markets, rising construction costs of TMEP, and advancement of other pipeline projects that are alternatives to TMEP.

The conclusions on the deficiencies of the NEB's evaluation of TMEP are consistent with other evaluations such as those completed by the Tsleil-Waututh Nation (Allan, 2016). Further, the impact of recent market developments that undermine the rationale for TMEP (including the weakening of oil demand and prices, escalating TMEP construction costs, and advancement of other pipeline projects) combined with the failure of the Government of Canada to provide the public with the business case for proceeding with TMEP is concerning. TMEP is among the largest single projects undertaken by the federal government and should be subject to a comprehensive evaluation before expenditure of public funds. Consequently, it is important to undertake an independent evaluation of TMEP to inform decision makers and the public on the prudence of proceeding.

4. Overview of Oil and Pipeline Markets

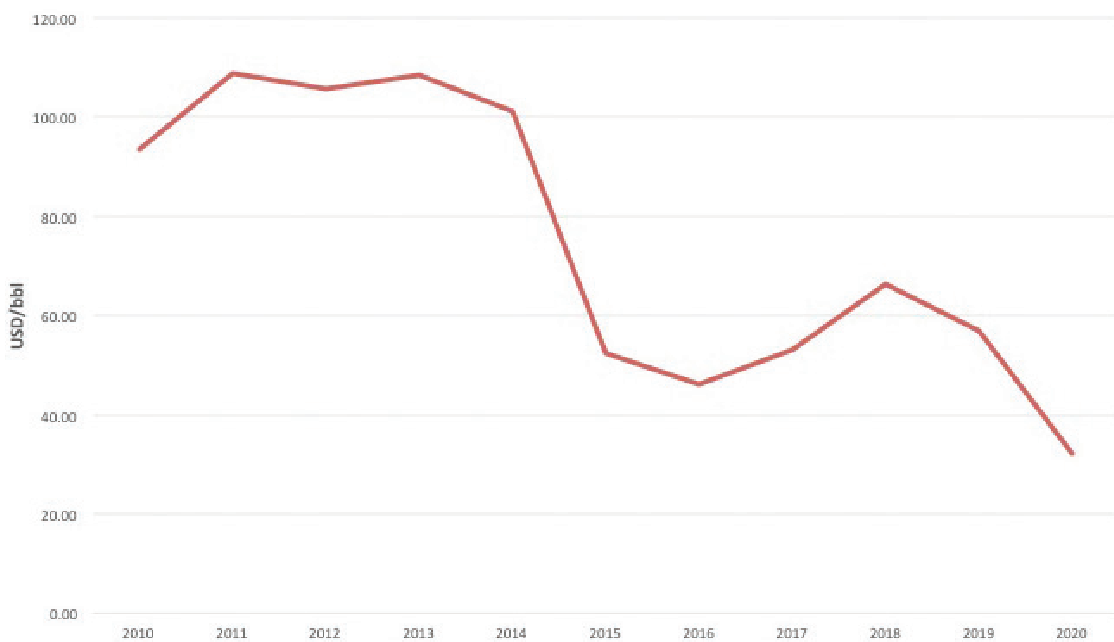
This section of the report provides an overview of oil markets and the supply and demand for pipeline capacity in the Western Canada Sedimentary (WCSB) and assesses the impact of these market trends on the economic viability of TMEP.

OIL MARKETS

A significant factor adversely impacting the economic viability of TMEP is the weakening of oil demand and oil prices. Oil prices have fallen from over $100 per barrel (USD, West Texas Intermediate (WTI)) in 2011 to under $50 per barrel in 2020 (Figure 4.1). Lower prices have resulted in lower production forecasts. The Canadian Association of Petroleum Producers' (CAPP) forecast for WCSB 2030 oil supply has fallen from 7.5 million bpd in its 2014 forecast to 5.9 million bpd in its 2019 forecast, a decline in forecast growth of 1.6 million bpd (CAPP, 2014; 2019). The decline in oil prices has also resulted in deteriorating financial health of oil companies and large write downs of oil assets, estimated at over $50 billion globally in 2020 (IEA, 2020c, p. 259). The International Energy Agency (IEA) estimates that if oil companies do not adjust to declining demand by reducing investments in new oil production capacity, they risk losing between $0.9 trillion and $1.2 trillion in stranded assets (IEA, 2020a, p. 85).

The market decline has accelerated with the COVID induced recession. The IEA (2020b) forecasts that world oil demand in 2020 will decline by 9% due the economic downturn, which will be the largest absolute annual decline on record. Industry has responded to weaker oil markets by cutting investment. Teck recently shelved its proposed 260kbpd Frontier oil sands mine and wrote off $1.24 billion of its investment in its Fort Hills mine (Teck, 2019; 2020). French energy giant Total wrote off $9.3 billion in oil sands assets in Canada and stated that it would not undertake any additional investments to expand Canadian production due to poor economics (CBC, 2020). Oil drilling has declined to close to a 50-year low, down 43% from 2019 (BNN, 2020b), and the Alberta Energy Regulator (AER) estimate of Alberta oil projects under construction has declined from 452kbpd in 2018 to just 63kbpd in 2020 (Table 4.1).

Figure 4.1 **WTI Crude Oil Prices (2010–2020)**



Source: CER, 2020a

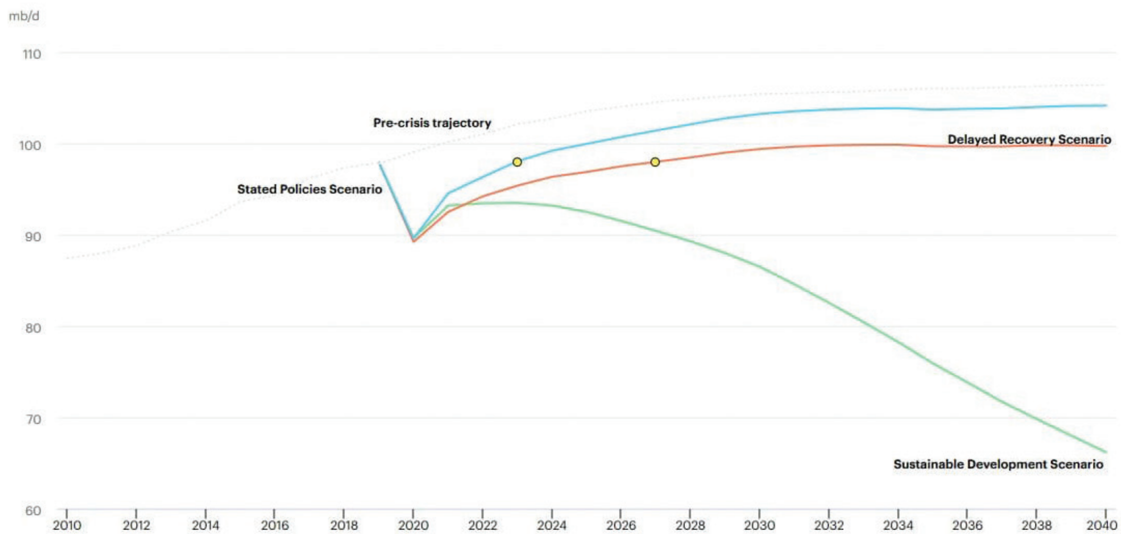
Table 4.1 **New WCSB Projects Under Construction, 2018 and 2020**

WCSB Projects 2018		**WCSB Projects 2020**	
Project	**kbpd**	**Project**	**kbpd**
Fort Hills Phase 1	194	Kinosis Phase 1 Southwest	37
Christina Lake Phases 2B	20	Christina Lake 2B	13
Orion Phase 2B	13	Orion Phase 2B	13
Aspen Phase 1	75		
Sunrise Phase 1B	60		
Christina Lake Phase G	50		
Kirby North Phase	50		
Total	452		63

Source: AER, 2018; 2020a

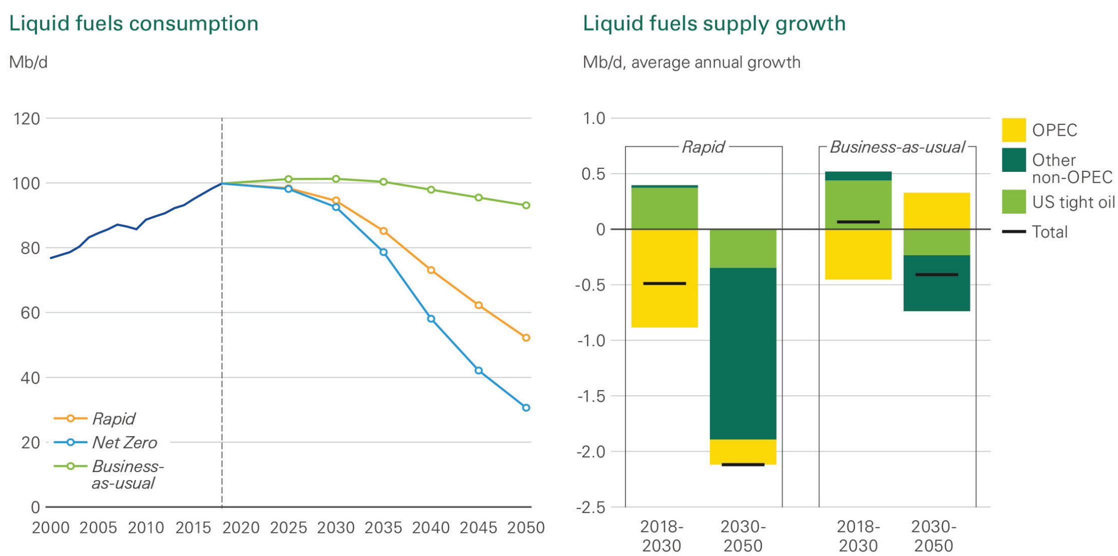
These recent developments in oil markets combined with stronger climate change policies will constrain future growth in oil production and demand for new pipeline capacity. The IEA (2020c) forecasts that the era of growth in oil demand will come to an end in the next ten years under its Stated Polices Scenario and that world oil production will have to decline by approximately one-third by 2040 to achieve the Paris commitments under its Sustainable Development Scenario (Figure 4.2). A recent forecast by energy giant British Petroleum (BP, 2020) forecasts

Figure 4.2 IEA World Oil Demand Forecast Scenarios



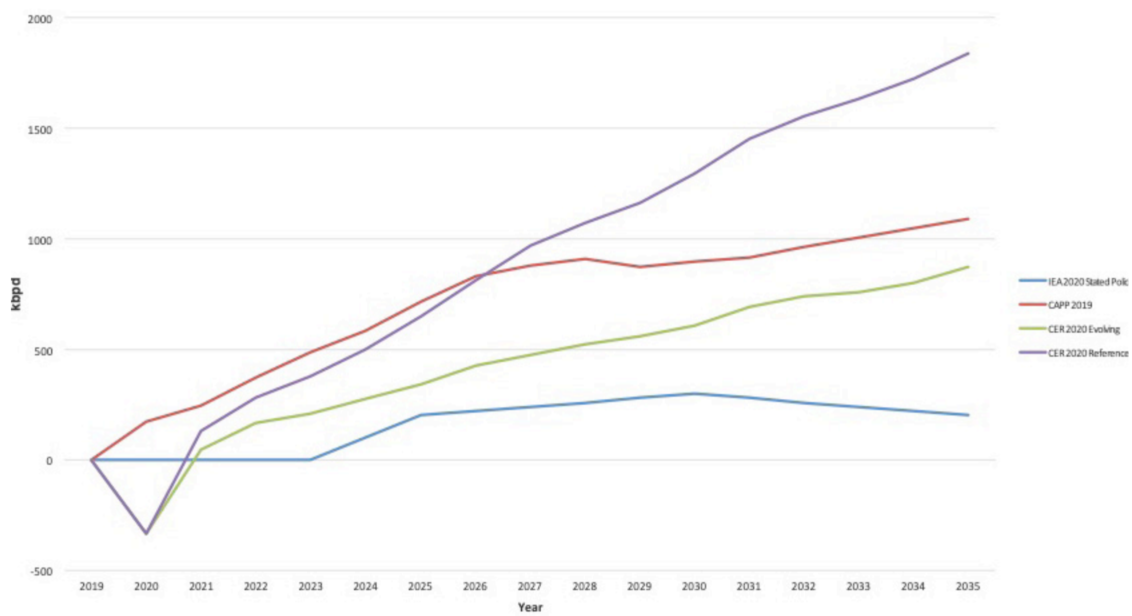
Source: IEA, 2020c

Figure 4.3 British Petroleum Forecasted World Oil Demand



Source: BP, 2020, p. 67

Figure 4.4 **Forecasts of Canadian Oil Production Growth (2019–2035)**



Sources:CAPP, 2019; CER, 2020b; IEA, 2020d
Notes: IIEA 2020 Stated Policies forecast does not specifically identify the COVID related impacts on Canadian oil production but assumes oil production growth returns to pre-pandemic levels in early 2023.

that oil demand has already peaked and will decline over the coming decades ranging from a modest decline to up to an almost 80% decline by 2050 (Figure 4.3). Weakening demand will have more significant downward impacts on Canadian oil production than other jurisdictions because Canadian oil sands production is among the highest cost and highest GHG intensity sources of oil in the world and will therefore be more heavily impacted than other jurisdictions (Jaccard et al., 2018; Rystad, 2020). Under the IEA Sustainable Development and BP scenarios, oil production would decline and there would be little to no need for any incremental oil transportation capacity.

The CER has attempted to assess the impacts of these market developments in its recent forecast released in November of 2020 (CER, 2020b). The CER forecast provides two Canadian energy production scenarios. One scenario, termed the Reference Scenario, assumes no additional policies by governments to address climate change beyond those currently in place. Given Canada's announcement of new climate change policies on December 11, 2020 (Canada, 2020), the CER Reference Scenario assumption of no new climate change policies is invalid and the Reference Scenario forecast is therefore no longer likely.

The other scenario, termed the Evolving Scenario, assumes additional government actions to meet climate change objectives will be implemented at the same rate as they have in the recent past in Canada and the world. In the Evolving Scenario forecast, which the CER defines as their primary scenario, fossil fuel consumption in Canada peaks in 2019 and declines over the forecast period by 12% to 2030 and by 35% to 2050 (CER, 2020b, p. 8). However, oil production continues to increase slowly to 2039 and then begins to decline to 2050. The Evolving Scenario's forecast increase in oil production is much lower than the CER's Reference Scenario forecast and CAPP's 2019 forecast, but higher than the IEA (2020c) Stated Policies forecast (Figure 4.4).

The CER notes that the climate policies assumed under the Evolving Scenario will not be sufficient to meet Canada's climate change objectives and stronger measures will therefore be required (CER, 2020b, p.62). Again, given Canada's recent climate plan announcement that proposes stronger climate policies to meet Canada's 2030 and 2050 net zero emissions target than those assumed in the CER Evolving Scenario, the Evolving Scenario likely overestimates Canadian oil and gas production (see Appendix 3). The CER Evolving Scenario is also significantly more optimistic than the BP (2020) forecast, which assumes global oil production has already peaked, and the IEA Sustainable Development forecast, which suggests a more dramatic production decline of about one-third by 2040 to meet Paris climate change objectives.

An additional factor adversely impacting Canadian oil production is the new International Maritime Organization shipping fuel standard to reduce sulphur emissions, which will put further downward pressure on Canadian oil production because Canadian heavy oil is high in sulphur. According to one recent study (CERI, 2018), these new standards could increase the discount on WCSB oil (Western Canada Select (WCS)) relative to WTI oil from about $13/b (2017 US $) to between $31-$33 per barrel, resulting in a significant decline in netbacks to Canadian producers and investment in new Canadian oil production capacity.

WCSB TRANSPORTATION CAPACITY

A second significant change adversely impacting the economic viability of TMEP is the emergence of new pipeline projects that will compete with TMEP. Currently, there is 1,640kbpd of new capacity under development for the WCSB without Keystone XL (Table 4.2). This increase in pipeline capacity is significantly higher that the forecasted increases in WCSB oil production, which range from 400kbpd (IEA, 2020d) to 1,210kbpd (CAPP, 2019) between 2018 to 2030. Many of these pipeline expansions (Enbridge Mainline, Express, Keystone, Rangeland) are low-cost capacity enhancements of existing pipelines. The two remaining projects (Enbridge Line 3 and TMEP) are new pipelines that are currently under construction. Keystone XL has been cancelled by the Biden administration, but it is partially constructed and could be completed sometime in the future if it is reapproved. In addition, there is 1,100kbpd of rail loading capacity for WCSB exports and rail shipments reached a peak of just over 400kbpd in February 2020 (CER, 2020c). It is important to note that the 1,640kbpd of pipeline expansions is more than one and a half times higher than the forecast of 960kbpd of expansions that was used by KM (MS, 2015) in its application to the NEB to justify TMEP.

Table 4.2 Existing and Proposed WCSB Oil Transportation Capacity

Pipeline	Nameplate Capacity (kbpd)
Enbridge Mainline	2,850
Express/Platte	280
Milk River/Rangeland	118
Trans Mountain	300
Keystone	590
Existing Pipeline Capacity Subtotal	**4,138**
Enbridge Line 3 expansion* (2021/22)	370
Enbridge Mainline expansions** (2019-2022)	350
Enbridge Southern Lights Reversal** (2022)	150
Express expansion*** (2020)	50
Keystone**** (2021)	50
Trans Mountain Expansion Project (2023)	590
Rangeland (2021)	80
Proposed Capacity Subtotal	**1,640**
Existing and Proposed Pipeline Capacity Total (no XL)	**5,778**
Keystone XL*****	830
Existing and Proposed Pipeline Capacity Total (with XL)	**6,608**
Rail Capacity******	175 – 1,100

Source: CAPP, 2019; AER, 2020b

Notes: *Potential for Line 3 Expansion to increase to 454kbpd (Minnesota, 2018.p. 55) so the 370kbpd capacity estimate is conservative.

**Enbridge expansions (Enbridge, 2020, pp.45,50) include 350kbpd mainline system optimizations (2019: 100kbpd; 2020: 50kbpd; post 2021: 200kbpd) and reversal of Southern Lights (post 2021: 150kbpd). Note that the CER (2020b) pipeline capacity forecasts do not include the 200kbpd post 2021 Enbridge mainline optimizations and the 150kbpd Southern Lights Reversal.

***Express expansion as estimated by Enbridge (2020, p. 45).

****As per BNN (2020c). The Keystone pipeline is permitted to ship an additional 170kbpd but TC Energy has indicated that it plans to move only an additional 50kkbpd by 2021. Further increases in Keystone shipments that could occur after 2021 are not included. Note the CER (2020b) pipeline capacity forecasts include a 70kbpd capacity increase for the Keystone pipeline.

*****Keystone XL has been cancelled by the Biden administration, but it is partially built and could be completed sometime in the future if it is reapproved

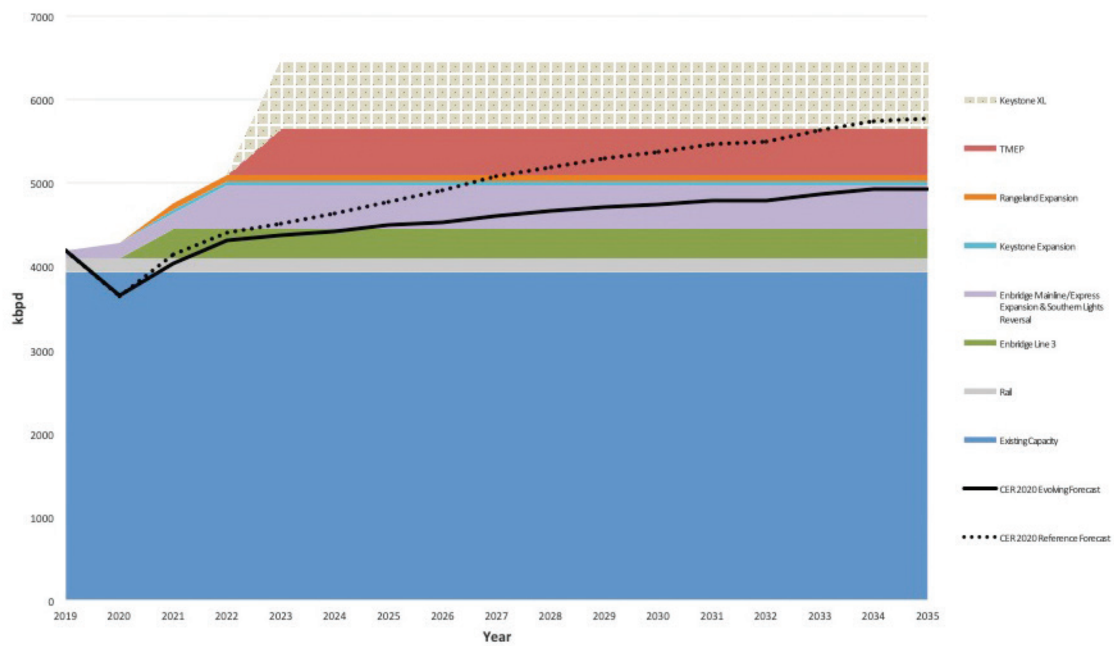
******There is no firm estimate of rail capacity given the flexibility in the rail system. CAPP (2019) estimates rail loading capacity at 1,100kbpd but there on constraints imposed by the availability of cars and rail line capacity. Maximum monthly rail shipments were just over 400kbpd in February 2020 (CER, 2020c) which measures effective capacity and the CER (2020b, Figure ES-8) estimates that rail shipments will remain at a minimum of 175kbpd even with surplus pipeline capacity to meet contractual obligations and serve refineries not suited for pipeline shipments (CER, 2020b). The 175kbpd is used in the supply and demand analysis (Figure 4.5).

WCSB TRANSPORTATION SUPPLY AND DEMAND BALANCE

The combination of weaker oil markets and expanding pipeline capacity has increased the financial risks for TMEP by creating the potential for excess pipeline capacity. To assess these risks, we compare the CER's forecast growth in WCSB oil supply for export with forecast pipeline capacity summarized in Table 4.2.

The results show that under the CER Evolving Scenario forecast neither TMEP nor Keystone XL are required to meet WCSB oil transportation needs (Figure 4.5). Building TMEP along

Figure 4.5 **Estimates of Western Canada Oil Supply and Transportation Capacity**



Sources: WCSB oil supply forecasts are from CER (2020b, Figure ES-8 data set). The CER WCSB oil supply forecasts incorporate several additional adjustments to the oil production forecasts to derive WCSB oil supply including net deduction of refinery consumption of WCSB oil from Alberta and Saskatchewan refineries to estimate the quantity of oil that is exported from the WCSB and addition of diluents to allow shipment of bitumen in pipelines. Pipeline capacity is shown on the basis of 95% capacity utilization. For oil transportation capacity sources see notes to Table 4.2. Appendix 4 provides the data inputs for this figure.

with the other proposed additions (but excluding Keystone XL) would result in over 900kbpd of redundant pipeline capacity in 2030. If Keystone XL is reapproved sometime in the future, there would be almost 1.7 million bpd of redundant capacity in 2030. Given that the Evolving Scenario likely overestimates WCSB production because it does not include all of the climate change measures announced in Canada's new climate plan and is more optimistic than other recent forecasts such as those by BP (2020) and the IEA (Figure 4.2, 4.4), the excess pipeline capacity could be even higher.

Under the higher CER Reference Scenario production forecast there would be sufficient oil transportation capacity without TMEP or Keystone XL until about 2028, at which point some additional transportation capacity may be required (Figure 4.5). Again, however, the CER Reference Scenario would only come to fruition in the unlikely event that Canada canceled all future climate change initiatives and is therefore considered an unrealistically high oil production forecast.

Our findings are consistent with the CER's forecast pipeline supply and demand that shows that neither Keystone XL nor TMEP are required under the Evolving Scenario (CER, 2020b, p.24).[3] Our findings are also consistent with another recent study by Dalman and Grant (2020).

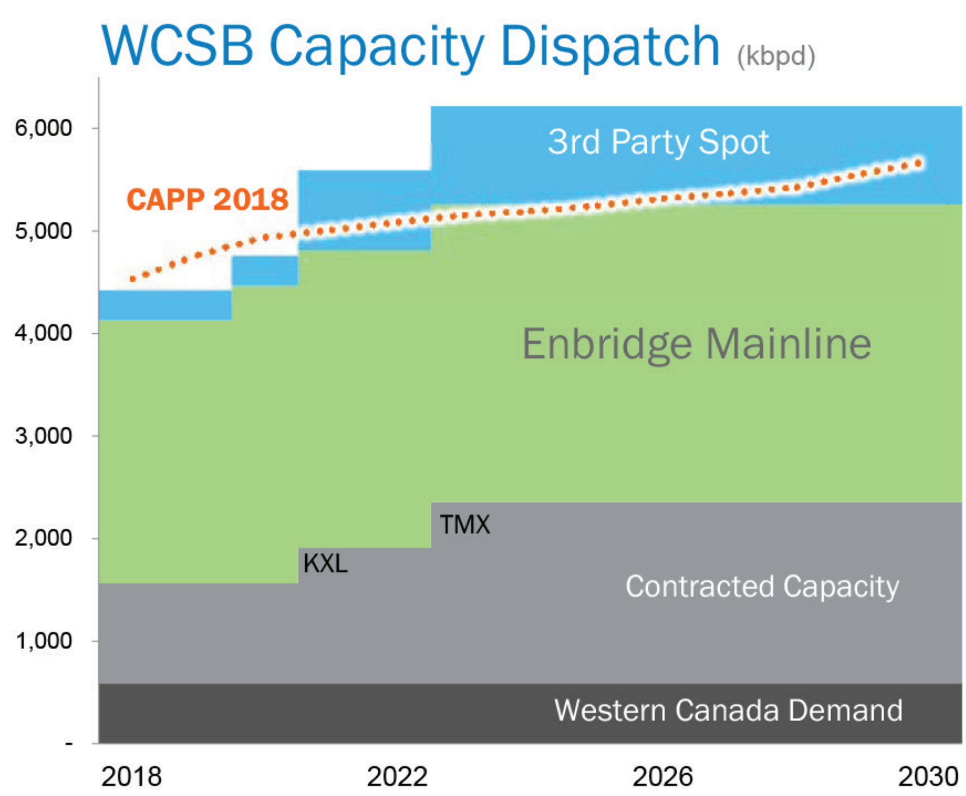
3 Although the CER shows that neither Keystone XL or TMEP are required under the Evolving Scenario, the CER's estimate of excess pipeline capacity is lower than our estimate because the CER forecast of pipeline capacity omits 200kbpd post 2021 Enbridge mainline optimizations and the 150kbpd Southern Lights Reversal announced by Enbridge (2020, pp.45,50).

The Dalman and Grant study estimates demand for pipelines based on the CAPP 2019 forecast, the IEA New Policies scenario, and two IEA scenarios consistent with meeting the Paris Agreement. The results show that under the IEA New Policies scenario neither TMEP nor Keystone XL are required. Under the IEA Sustainable Development and Beyond 2 Degrees scenarios neither TMEP, Keystone XL, or Enbridge Line 3 are required. The Dalman and Grant study cautions that the surplus capacity will create significant financial risk for new pipelines that are unable to fill uncontracted space and unable to renew long term contracts after they expire.

IMPACTS OF MARKET RISKS ON TMEP

TMEP has long term contracts with shippers for 80% of its capacity that will provide revenue even if there is excess pipeline capacity (NEB, 2019). However, the forecast excess pipeline capacity increases risks for TMEP in two ways. First, securing spot shipments for the 20% of TMEP capacity not under long-term contracts will be challenging. Enbridge is in the process of converting 90% of its capacity to long-term contracts, which will remove about 2.7 million bpd of oil from potential spot shipments (Enbridge, 2020, p. 43). Based on Enbridge's analysis, there will be very little oil available for spot shipments even under the higher CAPP (2019) and CER

Figure 4.6 **Contracted vs Spot Supply of WCSB Oil**



Source: Enbridge, 2018, p. 31

Table 4.3 **Pipeline Toll Comparison**

Pipeline	Shipment Type	2020 Toll (US $/b)
TMEP plus tanker	Heavy spot to South China	10.25–12.30
Enbridge Hardisty to US Gulf	Heavy	9.60–12.30
Keystone Hardisty to US Gulf	Heavy	9.51–12.20

Sources: Enbridge and Keystone tolls are from CAPP, 2019; TMEP tolls are estimated based on MS toll plus tanker costs (2015, p. 61–2) adjusted for capital cost increases from the original $5.4 billion estimate to the current $12.6 billion estimate based on the contract provision of $.07 per $100 million increase in cost as provided in the TM shippers' contracts (TM, 2013c). The lower end estimate is based on only the uncapped costs overrun being passed on to shippers (24%) and the higher end estimate is based on 100% of the cost overrun being passed on to shippers.

Reference Scenario (2020b) production forecasts after Enbridge converts to long-term contracts (Figure 4.6). Second, TMEP's ability to secure spot shipments will be further constrained by the escalating capital costs that will result in higher tolls and impair TMEP's ability to compete with other pipelines (Table 4.3) and the fact that other pipelines have better access to the US Gulf, which currently has higher heavy oil prices that the Asian market targeted by TMEP (see Appendix 2, Figure A2.1). The 80% contracted space on TMEP may also be at risk due to the inability of some shippers to honour their long-term contracts due to financial hardship and other shippers not renewing their long-term contracts after they expire due to the availability of lower cost options. The combination of these market developments will put downward pressure on TMEP shipments and cash flows, thus increasing the financial risks of the expansion. In addition, the excess capacity will result in a significant revenue loss for other pipelines that will lose shipments diverted to TMEP to honour the TMEP contracts. The economic cost of this excess capacity is included in the benefit cost analysis provided later in this report.

5. Financial Evaluation of the Trans Mountain Purchase and Expansion

THE PURPOSE OF THIS SECTION OF THE REPORT is to provide a financial impact analysis on the Canadian taxpayer of the Government of Canada's decision to purchase TM and build TMEP. The scope of the financial impact analysis includes assessment of only the costs and revenues accruing to government from TMEP but does not include other costs and benefits to Canada such as environmental and economic impacts that are assessed in the more comprehensive benefit cost analysis provided in a subsequent section of this report. Therefore, the financial impact analysis in this section of the report covers only a subset of the total costs and benefits of TMEP.

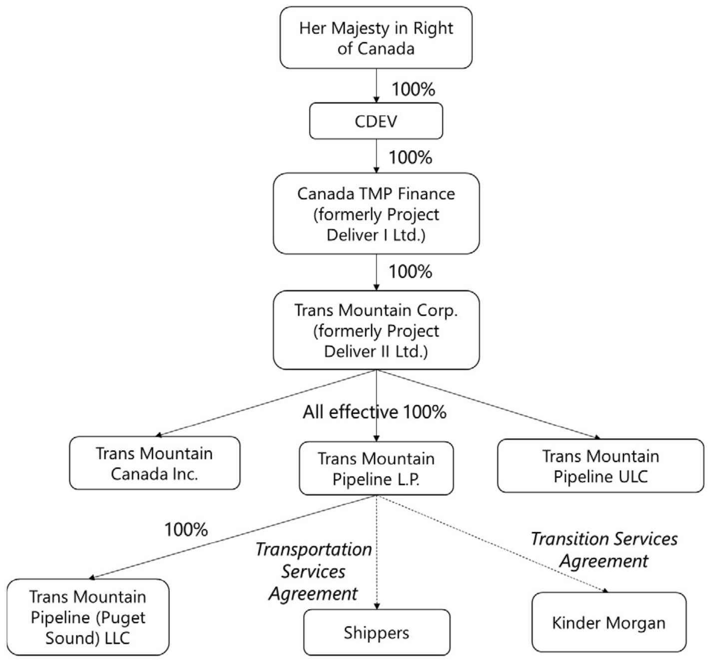
The financial impact analysis employs a similar methodology used by the Parliamentary Budget Officer (PBO) in their evaluations of TMEP (PBO, 2020; 2019) but assesses the financial impacts to government under a scenario where TMEP is constructed, put in-service, and then sold to a third party as planned. The PBO analyses do not consider the financial implications of a future sale. Sensitivity analysis is conducted which considers key areas of uncertainty. Additionally, the financial impact analysis assesses several incremental government costs generated by TMEP that are not included in the PBO analyses.

GOVERNMENT OWNERSHIP STRUCTURE

The government purchase of the TM assets involved several different legal and functional corporate entities (Figure 5.1). Trans Mountain Corp (TMC) ultimately owns and manages the pipeline system (including TMP, TMEP, and a number of other related assets) through a number of sub-entities. TMC is financed by Canada Trans Mountain Project Finance (TMPF), which is owned by Canada Development Investment Corporation (CDEV). CDEV is a Crown corporation used for government equity investments and commercial holdings.

Financing the purchase of the TM assets from Kinder Morgan involved TMPF borrowing $5.2 billion, through CDEV, from the Government of Canada Account (CDEV, 2020a). A to-

Figure 5.1 **TMC Organizational Chart**



Source: PBO, 2019

tal of $4.4 billion was paid to Kinder Morgan Canada, $0.5 billion was used to backstop a letter of credit and fulfill an NEB requirement for TMC to have sufficient resources to cover any environmental damages, and the remaining funds were made available for working capital as needed (CDEV, 2020a).

Funding for the continued construction of TMEP has come from additional borrowing by TMPF from the Government of Canada Account. As of March 31, 2020, a debt facility with a $4 billion limit has been made available to TMPF (CDEV, 2020b). This facility can be expanded through the borrowing authority of the Minister of Finance (CDEV, 2020b). TMPF has a funding agreement under which cash proceeds of each funding request are comprised of 55% debt funding and 45% equity funding (TMC, 2020a). This is important because the interest charges incurred by TMC are not equivalent to the interest charges incurred by TMPF on the debt used for acquisition and construction. It is therefore necessary to analyze the future financial results of this pipeline operation by looking at the consolidated results of TMC and TMPF.

The Government of Canada has stated that it does not plan to own the Trans Mountain assets over the long term and intends to sell the assets to a private entity. CDEV is expected to maintain readiness on an ongoing basis to sell the Trans Mountain assets (CDEV, 2018).

PBO STUDY: SUMMARY OF STUDY AND MAJOR FINANCIAL FINDINGS

PBO assessed the Government of Canada's decision to acquire, expand, and operate the Trans Mountain pipeline system in a December 2020 report (PBO, 2020), which updates their previous reporting from February 2019 (PBO, 2019). PBO's 2020 report uses a discounted cash flow (DCF) methodology to determine the net present value (NPV) of the TMC cash flows from the year of the acquisition to year 40 of the expanded system operations. The 2020 PBO report considers the NPV of the TMC cash flows net of the purchase price paid for the assets to show the net fiscal impact of the government acquisition.

The financial projections for PBO's (2020) DCF analysis were provided by CDEV; however, CDEV classified the data as commercially confidential. While PBO was able to use the financial data for their analysis, it was not released for public review. In addition to the confidential financial data, the PBO (2020) analysis relies on a number of assumptions related to capital costs, in-service dates, volume throughputs, and other variables for their reference case and sensitivity analysis (Table 5.1).

A number of these assumptions have been updated from the 2019 PBO report. The capital cost and in-service date assumptions reflect the current estimates, and the TMEP long-term discount rate assumption has been lowered by 1.5 percentage points, which reflects lower perceived project risks and lower benchmark interest rates (PBO, 2020). PBO has also expanded their sensitivity analysis to look at the effects of differing throughput levels and tolling frameworks. In the reference case, an important difference between the 2019 PBO report and the 2020 PBO report is the change from a cost-of-service tolling framework to a contracted service tolling framework following the expiry of the long term (20 year) contracts. PBO has highlighted in their discussion that there is a risk that shipper's will choose not to re-enter into long term contracts in later years, particularly if the volume of Western Canadian crude oil produced and available for export declines in the future because of enhanced climate policy (PBO, 2020).

TABLE 5.1 **Reference Case and Sensitivity Assumptions Used in the PBO (2020) Financial Analysis**

Assumption	Reference Case	Sensitivity
TMEP Total Capital Cost	$12.6 billion	+/-10%
TMEP In-Service Date	December 31, 2022	One Year Delay
TMP Volume Throughput	80% contracted utilization + near full spot utilization in initial years and moderate spot utilization in subsequent years	+/-5% Total Capacity
Service and Tolling Framework	Long term contracts renewed upon expiry	Cost-of-service tolling framework following expiry of long-term contracts
Discount Rate	8.5%	+/-0.5%
Climate Policy Framework	CER Reference Scenario Forecast	CER Evolving Scenario Forecast

SOURCE: PBO, 2020

Table 5.2 NPV of the Trans Mountain Pipeline System under Different Assumptions

(2018 $ millions)			Service and Tolling Framework After 20-Year Contracts Expire					
			Contract Service			Cost-of-Service		
In Service Date	Capital Costs	Pipeline Utilization	Discount Rate			Discount Rate		
			8.0%	8.5%	9.0%	8.0%	8.5%	9.0%
Dec 31, 2022	$11.3 billion (-10%)	+5.0%	$2,300	$1,300	$500	$200	-$400	-$1000
		-	$1,900	$1,000	$200	-$100	-$700	-$1,300
		-5.0%	$800	$0	-$700	-$900	-$1,400	-$1,900
	$12.6 billion	+5.0%	$1,900	$900	$100	-$200	-$800	-$1,400
		-	$1,500	$600	-$200	-$500	-$1,100	-$1,700
		-5.0%	$400	-$400	-$1,200	-$1,300	-$1,900	-$2,400
	$13.9 billion (+10 %)	+5.0%	$1,500	$500	-$300	-$600	-$1,200	-$1,800
		-	$1,100	$200	-$700	-$900	-$1,500	-$2,100
		-5.0%	$0	-$900	-$1,600	-$1,700	-$2,300	-$2,800
Dec 31, 2023	$11.3 billion (-10%)	+5.0%	$1,200	$300	-$400	-$600	-$1,200	-$1,700
		-	$800	$0	-$700	-$800	-$1,400	-$2,000
		-5.0%	-$100	-$900	-$1,600	-$1,500	-$2,100	-$2,600
	$12.6 billion	+5.0%	$800	-$100	-$900	-$1,000	-$1,600	-$2,200
		-	$400	-$400	-$1,200	-$1,200	-$1,800	-$2,400
		-5.0%	-$600	-$1,300	-$2,000	-$2,000	-$2,500	-$3,000
	$13.9 billion (+10 %)	+5.0%	$400	-$500	-$1,300	-$1,400	-$2,000	-$2,600
		-	$0	-$800	-$1,600	-$1,600	-$2,300	-$2,800
		-5.0%	-$1,000	-$1,800	-$2,500	-$2,400	-$3,000	-$3,500

Source: PBO, 2020

Based on these varying assumptions, PBO (2020) provides estimates of the financial impact of the government's purchase of TMC ranging from positive $2.3 billion to negative $3.5 billion, with a reference case estimate of positive $600 million (Table 5.2). These results are net of the $4.4 billion government acquisition cost.

An obvious question is which of these PBO scenarios is the most likely. As discussed above, the financial value of TMC is highly contingent on the climate policy stance of the federal government. More stringent climate action would reduce the total volume of oil available for export, reduce spot shipments on Trans Mountain, and increase the likelihood of shippers switching to cost-of-service contracts. PBO concludes (and shows in the sensitivity analysis) that possible future climate policy will likely lead to a negative NPV for the Trans Mountain assets (PBO, 2020).

This finding is pertinent because on December 11, 2020 the federal government unveiled its climate plan that aims to achieve net-zero emissions in Canada by 2050 (Canada, 2020). The PBO report was released on December 8th, 2020 prior to this announcement. As discussed in Sections 4.1 and Appendix 3, the federal government plan to achieve net-zero emissions is inconsistent with the assumption of no new climate policies used in the CER Reference Scenario and the Reference Scenario forecast is therefore no longer likely. Given the new climate policies, we conclude that the results in the PBO's sensitivity analysis (which uses the CER Evolving Scenario and the cost-of-service tolling framework) are more likely than the results in their reference case. Based on a capital cost of $12.6 billion and cost-of-service contracts, the PBO estimates that the net cost of the government's purchase of TMC ranges from negative $0.2 billion to negative $3.0 billion. If spot shipment volumes decline by 5%, which is likely given the lower CER Evolving Scenario forecast, the PBO estimates that the losses will range between negative $1.3 billion and negative $2.8 billion.

FINANCIAL EVALUATION METHODS

The financial impact analysis in our report uses the same discounted cash flow methodology used by PBO (2020; 2019) and includes the government purchase price in the presentation of the results. Our analysis relies on the publicly available TD Bank financial data provided in the KM report to shareholders (KM, 2018a). This is the same source used by the PBO in their 2019 report. The TD bank data has been adjusted to reflect the increase in estimated construction costs from $9.3 billion to $12.6 billion, the delay in the completion date from December 2021 to December 2022, and other current information on TMEP and oil markets. All TMP and TMEP cash flows are discounted to 2020. Further assumptions regarding the financial information used in the analysis are discussed in Appendix 5. A sensitivity analysis is performed on key variables as outlined in Table 5.3.

There are several differences between our financial analysis and the PBO (2020) financial analysis. First, our analysis presents a financial valuation under a scenario where TMP and TMEP are sold to a private investor in 2024. This is consistent with the federal government's stated intention to divest of the assets once they are operational (CDEV, 2018; PBO, 2020). The PBO (2020) report does not include this analysis but assumes that the pipeline system would be sold at a market value equal to the NPV. Second, the PBO analysis discounts the cash flows back to 2018 (the time of the government acquisition) whereas our analysis discounts the cash flows

Table 5.3 Base Case and Sensitivity Analysis Assumptions

	← Low		Base Case	High →	
TMEP Discount Rate	6%	8%	10%	12%	
TMEP Capital Cost			$12.6 billion	$13.9 billion (+10%)	
TMEP In-Service Date			December 31, 2022	December 31, 2023	
TMC Volume Throughput	80%	90%	95%		
Required Rate of Return for Purchaser of TMC		10%	12%	14%	16%

Table 5.4 Key Similarities and Differences between Base Case Assumptions in this Report and Reference Case Assumptions in the PBO (2020) Report

	This Report	PBO (2020) Report
Discount Rate for TMC cash flows	10% for TMEP and 6% for TMP	8.5%
Discount Rate for Private Purchaser Acquisition of TMC	10% to 16%	Not assessed
TMEP Capital Cost	$12.6 billion	$12.6 billion
TMEP In-Service Date	December 31, 2022	December 31, 2022
Volume Throughput	95%	80% contracted utilization + near full spot utilization in initial years and moderate spot utilization in subsequent years
Service and Tolling Framework	Cost-of-service tolling framework following expiry of long-term contracts	Long term contracts renewed upon expiry

to the present time period (2020). Third, our financial analysis relies on the TD bank analysis data (KM, 2018a), which focuses on the forecasted cash flows of TMP and TMEP (KM, 2018) to determine the fair market value of the assets being sold to the government. The PBO (2020) analysis uses the confidential CDEV financial forecast data. Without access to the confidential data, we are unable to assess differences in assumptions and cash flow projections between the TD and CDEV forecasts. Other differences between the base case and sensitivity assumptions in the analyses are summarized in Table 5.4.

FINANCIAL FINDINGS

In the scenario where the government sells TMP and TMEP in 2024, the net financial impact on government is the NPV of the cash flows, which include the purchase price paid in 2018 to acquire the assets, proceeds from the selling of the assets in 2024, and the net revenues resulting from the construction of TMEP and operation of the pipelines from 2018–2024.

The NPV of the construction, operation and selling of the assets is summarized in Tables 5.5 and 5.6. The cash flows from operations and construction are based on the TD financial analysis (KM, 2018a). The revenue from the sale of the assets is based on an estimate of what selling price a private entity would be willing to pay for the completed project in 2024. A private buyer would base their purchase price on the NPV of projected cash flows discounted at the private sector target rate of return. KM states that its target rate of return is 15% on capital investments but may be lower for pipelines and terminals that are underpinned by long-term take-or-pay contracts (KM, 2018b). Kinder Morgan's actual returns on invested capital have been closer to 12% over the last five years (KM, 2020) and this *ex post* rate of return of 12% is used in the analysis as the base case discount rate that a private pipeline operator would apply to the future

Table 5.5 DCF Analysis of TMP

(2020 $ millions)	2018	2019	2020	2021	2022	2023	2014
Unlevered Free Cash Flow	153	142	164	165	132	131	1,028
Discount Factor	1.12	1.06	1.00	0.94	0.89	0.84	0.79
Discounted Cash Flow	172	151	164	156	117	110	814
Cumulative Total	172	323	487	643	760	870	1,684

Table 5.6 DCF Analysis of TMEP

(2020 $ millions)	2018	2019	2020	2021	2022	2023	2014
Unlevered Free Cash Flow	(187)	(1,256)	(2,991)	(2,226)	(2,223)	994	9.808
Discount Factor	1.21	1.10	1.00	0.91	0.83	0.75	0.68
Discounted Cash Flow	(226)	(1,381)	(2,991)	(2,024)	(1,837)	747	6,699
Cumulative Total	(226)	(1,607)	(4,598)	(6,622)	(8,459)	(7,713)	(1,0.13)

Table 5.7 Net Fiscal Impact of the Government's Acquisition and Future Sale of TMC

(2020 $ millions)	
PV of Cash Flows TM	$870
PV of Cash Flows TMEP	($7,713)
PV of Acquisition Costs	($5,490)
PV of Sale Price	$7,513
Total	**($4,819)**

TMP and TMEP cash flows to determine a purchase price. The forecast cash flows are taken from the TD forecast (KM, 2018), adjusted for the higher capital costs and delayed completion date to December 31, 2022. Valuing the cash flows from 2024 onward using a 12% discount rate gives an NPV of $10,836 million, which is the cash sale price that would be realized in 2024. For the Government of Canada, the present value of this sale price is $7,513 million (when using the TMEP discount rate of 10%). The net fiscal impact if the government sells the assets in 2024 is therefore a loss of $4,819 million (Table 5.7).

A sensitivity analysis is conducted by testing the impact of alternative discount rates, completion dates, capital costs, throughput, and purchaser rates of return (Table 5.8). The results show that the net loss to the Government of Canada could range between $2,158 million and $6,902 million.

Table 5.8 Sensitivity Analysis on the Net Fiscal Impact of the Government's Acquisition and Future Sale of TMC

(2020 $ millions) NPV of cash flows (including Trans Mountain acquisition costs and 2024 sale proceeds))	Discount Rate 6%	8%	10%	12%
In-Service Date				
12/31/2022	($3,421)	($4,142)	($4,819)	($5,458)
12/31/2023	($4,268)	($4,959)	($5,592)	($6,190)
Construction Costs				
$12.6B	($3,421)	($4,142)	($4,819)	($5,458)
$13.9B (10% Higher)	($4,064)	($4,779)	($5,450)	($6,084)
Throughput				
95%	($3,421)	($4,142)	($4,819)	($5,458)
90%	($3,578)	($4,455)	($5,111)	($5,730)
80%	($4,881)	($5,499)	($6,083)	($6,636)
Required Rate of Return (Purchaser)				
10%	($2,158)	($2,963)	($3,716)	($4,424)
12%	($3,421)	($4,142)	($4,819)	($5,458)
14%	($4,404)	($5,060)	($5,678)	($6,263)
16%	($5,183)	($5,788)	($6,359)	($6,902)

ADDITIONAL FISCAL COSTS

In addition to the direct costs to the federal government of purchasing TM and building TMEP, there are additional costs to government associated with the expanded pipeline system. Principally, these are:

- costs associated with the Oceans Protection Plan (OPP) and other activities to mitigate the risks and adverse impacts of TMEP that fall under the federal jurisdiction; and
- lost federal income tax revenues resulting from the diversion of oil shipments on other Canadian pipelines to TMEP.

Offsetting these additional costs are $325 million in capital gains tax revenues (KM, 2018a), which are a result of the sale of the TM assets from Kinder Morgan Canada to the Government of Canada.

OCEANS PROTECTION PLAN

In re-approving TMEP in 2019 with the NEB's conditions and recommendations, the federal government agreed to a number of marine protection initiatives (NEB, 2019) that have a fiscal impact, including but not limited to:

- the development and implementation of a regional cumulative effects management plan in the Salish Sea;
- a marine bird monitoring and protection program;
- a feasibility study for establishing a Southern Strait of Georgia National Marine Conservation Area Reserve;
- an offset program for underwater noise and marine mammal strike risks;
- continued engagement with Indigenous communities on marine safety, environmental monitoring, and community response capacity;
- the development and implementation of greenhouse gas reduction measures related to marine shipping; and
- the development of marine safety regulations and initiatives, particularly for oil spill resolution.

These initiatives are largely funded through the $1.47 billion OPP over a five-year period (2016–2021) (TC, 2020a) and to a lesser extent through the $167 million Whales Initiative and $62 million in other southern resident killer whale programs (NEB, 2019). Although Transport Canada has said that the OPP is independent of TMEP and has widespread benefits (NEB, 2019), there are specifics of the OPP that have a direct application to TMEP's marine shipping components and/or are a response to TMEP concerns raised through Indigenous and public consultation. The OPP has also been repeatedly referenced in the NEB's Reconsideration report as a response to project specific concerns (NEB, 2019).

Based on the current information, it is not possible to accurately estimate the OPP expenditures incurred as a result of TMEP. Nonetheless, some proportion of the OPP expenditures are attributable to TMEP and additional analysis should be undertaken to estimate these costs to provide a full cost accounting of the financial impacts of TMEP on government.

NET FEDERAL CORPORATE INCOME TAX REVENUE

The construction and operation of TMEP is likely to reduce federal corporate income tax (CIT) revenue because of unused oil transportation capacity costs. In estimating the fiscal impact of the unused capacity on federal income tax revenues we consider the difference between two scenarios:

a. a scenario where TMEP does not exist and oil is shipped on Canada's largest pipeline, the Enbridge Canadian Mainline; and

b. a scenario where TMEP does exist and oil is diverted from Enbridge to TMEP to fulfill contractual obligations on TMEP.

The impact of scenario B, in which TMEP is built, is that oil will be diverted from Enbridge to TMEP resulting in a revenue loss and lower corporate income tax payments by Enbridge. The diverted shipments will generate incremental net revenue for TMC and incremental CIT pay-

Table 5.9 NPV of the Federal CIT Lost as a Result of Building TMEP

(2020 $ millions)	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2050	2060
UCC TMEP	12,600	11,403	10,320	9,339	8,452	7,649	6,922	6,265	3,803	2,309	851	314
CCA @ 9.5%Factor	1,197	1,083	980	887	803	727	658	595	361	219	81	30
Statutory Federal Tax Rate @15%	180	162	147	133	120	109	99	89	54	33	12	4
Discount Factor @10%	0.75	0.68	0.62	0.56	0.51	0.47	0.42	0.39	0.24	0.15	0.06	0.02
Discounted Taxes	135	111	91	75	92	51	42	34	13	5	1	0
Cumulative Total (Net Tax Loss)	**135**	**246**	**337**	**412**	**474**	**525**	**567**	**601**	**701**	**738**	**758**	**761**

ments. However, the taxable income per barrel of oil diverted from Enbridge to TMEP will be lower than what the taxable income per barrel of oil was on Enbridge because TMC will be able to deduct depreciation costs of its investment in the new pipeline. If TMEP was not built and the oil was shipped on Enbridge, this depreciation deduction would not occur. In effect, building TMEP results in depreciating additional capital costs of $12.6 billion to ship the same quantity of oil that would have been shipped without TMEP as long as there is surplus capacity in the pipeline system.[4]

The income tax loss resulting from TMEP is estimated by multiplying the statutory federal CIT rate of 15% (Canada, 2020) times the reduction in taxable income as measured by the depreciation costs resulting from the $12.6 billion investment in TMEP for each year that oil is diverted from the existing Enbridge pipeline system. The depreciation cost is estimated based on an annual declining balance capital cost allowance (CCA) of 9.5%.[5]

Estimating the number of years that shipments on TMEP are comprised of oil diverted from Enbridge is based on the supply and demand analysis of pipeline capacity summarized in Figure 4.5 in this report. The estimate is based on the CER Evolving Scenario and Keystone XL not being constructed. Under this scenario, TMEP is not required throughout the forecast period and oil would be diverted from Enbridge to TMEP from 2023 onwards.

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4 It is also possible that Enbridge recoups the loss of revenue from reduced shipments by increasing tolls to maintain its regulated return on capital. In this case, the taxable income of oil producers shipping on Enbridge would be reduced and the CIT loss would result from lower CIT payments by oil producers.

5 The CCA rate is provided by Trans Mountain in their NEB filings and is most likely a blend of class 6 (10%), class 7 (15%), and class 49 (8%) CCA depreciation rates for storage tanks, pumping & compression equipment, and pipelines, respectively (CER, 2013b).

The estimated NPV of the federal income tax loss associated with TMEP under these assumptions is $761 million (Table 5.9). We caution that estimating the tax losses is challenging and more analysis is required, but we have provided a rough order of magnitude estimate to show that it is a significant financial impact that should be taken into account. We also note that there may be other tax implications of TMEP related to impacts on oil prices and other economic effects of TMEP. These potential impacts are assessed in the benefit cost analysis in the following section of this report.

SUMMARY

The summary results from the financial evaluation of the Government's purchase and construction of TMEP shows that TMEP will result in a net loss to government under base case assumptions of $4.8 billion if the government sells TMC. The financial impacts range from a loss of $2.1 billion to a loss of $6.9 billion. In addition, there may be a net CIT loss due to higher depreciation charges associated with the incremental capital costs of TMEP as well as other government expenses generated by the OPP. As a final comment, it should be noted that this financial impact analysis is constrained by the lack of transparency of financial forecast data on TMC and it is recommended that the TMC data be made public to allow for an independent comprehensive financial evaluation.

6. Benefit Cost Analysis of TMEP

The previous section of the report assessed the impacts of the Government of Canada's decision to purchase TM and build TMEP on Government of Canada finances. This section of the report broadens the economic evaluation to include an assessment of all of the costs and benefits of TMEP to determine whether TMEP generates a net benefit to Canada. This assessment is done by completing a benefit cost analysis (BCA), which is a more advanced and rigorous method for comparing benefits and costs than the one used by the NEB in its assessment of TMEP. 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 (Pearce et al., 2006; Zerbe and Bellas, 2006; TBCS, 2007; Shaffer, 2010; Boardman et al., 2017).

The steps in BCA are: (1) specify the alternative scenarios (with and without the project) that will be assessed, (2) determine standing (the jurisdiction and scope of interests that will be assessed), (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., 2017).

A challenge in BCA is identifying the distribution of impacts and valuing impacts that cannot be easily translated into monetary terms. To address these and other concerns a modified BCA approach termed Multiple Accounts Benefit Cost Analysis is used that disaggregates costs and benefits by stakeholder and by type of cost and benefit and explicitly recognizes that not all costs and benefits can be reliably and meaningfully translated into monetary units (Shaffer, 2010). A range of sensitivity analyses are completed to test how results may change under alternative assumptions and forecasts. Where applicable, Canadian benefit cost analysis guidelines published by the federal government are used in the BCA (TBCS, 2007).

BCA OVERVIEW AND ASSUMPTIONS

The components of the potential benefits and costs of TMEP included in the BCA are listed in Table 6.1. The benefits of TMEP include: toll revenues associated with transporting WCSB oil to market; potential increases in oil netbacks and option value by accessing new markets and reducing transportation costs; employment generation; and tax revenue. The costs of TMEP include: capital and operating costs; costs of unused capacity created on the Canadian oil pipeline system; net costs to BC Hydro of supplying power to TMEP; environmental externality costs including GHG emissions, air pollutants, potential damages from oil spills, and other environmental and social costs.

The BCA is structured in two ways: a "full project" BCA of the decision to build TMEP and a "project completion" BCA of the decision to finish building TMEP now that it is partially constructed. The full project BCA is relevant for determining the net benefits to Canada of the decision to approve and build TMEP relative to not building it. The project completion BCA is relevant for determining the net benefits of completing construction of TMEP relative to terminating construction. The difference between the two BCA assessments is that the full project BCA includes all costs and benefits from the start of construction in 2017, while the project completion BCA includes only future capital costs and benefits from 2021 onwards. Capital costs

Table 6.1 Components of TMEP Benefit Cost Analysis

Component	Benefit	Cost
TMEP Pipeline Operations	Toll revenue	Capital and operating costs
Unused Oil Transportation Capacity		Cost of unused oil transportation capacity (reduced net revenues of impacted transportation capacity and/or opportunity cost of unused capacity)
Option Value/Oil Price Netback	Increased netbacks to producers	
Employment	Increased wages and employment generated by TMEP	
Tax Revenue	Tax revenue gain to government	Tax revenue loss to government
Electricity		Net cost of supplying electricity to TMEP
Air Emissions		Damage costs from TMEP air emissions
GHG Emissions		Damage costs from TMEP GHG 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*	Other environmental costs*
Other Socio- economic Costs and Benefits	Other socio-economic benefits*	Other socio-economic costs*

Note: *These components are identified but not estimated in monetary units in our BCA (see Appendix 1)

Table 6.2 Base Case and Sensitivity Assumption for the Benefit Cost Analysis

Component	Base Case	Sensitivities
TMEP Pipeline	Tolls set to cover $7.4 billion capital cost as approved by shippers in final cost estimated	Tolls set to cover $7.4 billion capital cost and all uncapped capital cost overruns (estimated at 24% of costs above $7.4 billion) plus variable costs
Unused Capacity Costs	Net revenue loss from unused capacity on Enbridge based on Enbridge estimate of net revenue loss per barrel	Unused capacity cost based on TMEP unused capital cost
TMEP Capital Costs*	$12.6 billion for the full project BCA; $5.6 billion for the project completion BCA	+10% cost overrun
WCSB Oil Supply	CER 2020 Evolving Scenario	CER 2020 Reference Scenario
Transportation Capacity	Existing pipelines plus all proposed pipelines at 95% nameplate capacity as listed in Table 4.2 (excluding Keystone XL)	1. Base case transportation capacity plus Keystone XL (830kbpd) 2. Base case transportation capacity with no rail (175kbpd), no Southern Lights reversal (150kbpd)
Option Value/Oil Price Netback	No oil price netback	Average historical Asian premium estimated by MS (2010; 2012) from 2000–11 applied to 500kbpd shipped on TMEP until 2039
Employment	Benefit of 10% applied to construction employment income	Benefit of 15% applied to construction and operations employment income
Tax Revenue	Property tax revenue	Property tax revenue plus royalty and income tax revenue from a price premium induced by TMEP
Electricity	Net revenue to BC Hydro from supplying electricity to TMEP	No sensitivity
Air Emissions	Average damage costs from air pollution resulting from construction and operation of TMEP	No sensitivity
GHG Emissions	Social damage costs based on US government reference per unit costs times quantity of direct TMEP GHG emissions	Social damage costs based on US government high per unit costs times quantity of direct TMEP GHG emissions
Pipeline Oil Spills	PHMSA average spill damage cost of $15,000/barrel	No sensitivity
Tanker Oil Spills	In port spills – OSRA model probability (0.031 annual probability) and spill size of 50,313 barrels	1. Higher estimate: OSRA in port/at sea tanker spill probabilities (0.071 annual probability) 2. Lower estimate: TM probability for tanker and terminal spills (0.011 annual probability) and (lower spill size (8,184 barrels)
Passive Use Damages from Oil Spill	No passive use damages	Passive use damages based on WTA – BC households
Discount Rate	8%	1. 10% 2. 3% 3. dual discount rate of 3 % for environmental and health impacts (oil spills, GHG emissions and air emissions) and 8% for all other impacts

Note: *These capital costs include capitalized financing costs. The capital costs used in the BCA calculations are net of financing costs and are $10.0 billion for the full project and $4.5 billion for the project completion.

incurred up to the end of 2020 are deemed sunk costs not relevant to the decision on whether to complete the partially built project. Both BCAs assume operation of existing oil transportation facilities and completion of new oil transportation projects listed in Table 4.2 (excluding Keystone XL). Following the guidelines of the Treasury Board of Canada Secretariat (TBCS, 2007), it is assumed all Canadians have standing so that TMEP is evaluated from the perspective of Canada and a number of sensitivity analyses are completed to test the impacts of alternative assumptions on the results (Table 6.2). The BCA is conducted as of 2020, all costs and benefits are reported in 2020 Canadian dollars unless otherwise stated, and the costs and benefits are estimated over a 30-year operating period.

For the base case full project and project completion BCA the recommended TBCS (2007) uniform real discount rate of 8% is used, with sensitivities of 10%, and 3%. While uniform discount rates are normally used in BCA, there is also support in the literature for using dual discount rates in which environmental and health impacts are discounted at a lower rate than other impacts to reflect the higher value that society places on them (e.g. Boardman et al., 2010; Brouwer et al., 2005; Freeman and Groom, 2016; Kolosz and Grant-Muller, 2015; Kula and Evans, 2011; Luttrell, 2011; Postma et al., 2013; Sáez and Requena, 2007; Van Wee and Tavasszy, 2008). The US government, for example, employed dual discounting in recent regulatory impact analyses of carbon pollution policy (Wright, 2017), employing rates of 2.5% to 5% for GHG impacts and rates of 3% and 7% for other impacts. Based on this literature, we include a sensitivity analysis using a dual discount rate of 3% for environmental and health impacts and 8% for all other impacts.

TRANS MOUNTAIN PIPELINE OPERATIONS

As indicated in our supply and demand analysis, building TMEP along with other proposed projects would result in significant unused transportation capacity. However, because TMEP has take or pay shippers' contracts for 80% of its proposed capacity, it is assumed that the unused capacity will be created on other pipelines that currently do not have long-term contracts as shippers divert oil to fulfill their contractual obligations to TMEP. The costs and benefits of this excess capacity on the other pipelines are estimated in Section 6.3.

For the purposes of the TMEP pipeline operations, we assume that the benefit is the toll revenue received for transporting oil to market. Tolls for TMEP are set to cover all the operating and capital costs of the pipeline as defined in the TMEP toll hearings. We assume that TMEP will be fully utilized, or at least in accordance with the utilization rate used to determine the cost recovery tolls and as provided for in the TMEP shippers' contracts (TM, 2013b; 2013c). Tolls are supposed to be set to cover the costs of TMEP, so the net present value of the costs of capital and operation should be equivalent to the net present value of the toll revenue. Therefore, the net benefit (revenue less cost) of the direct operation of the pipeline should be nil.[6] However, if

6 Although the direct operation of 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.

the TMEP costs are higher than forecast in the toll hearing there will be a net cost because toll revenues will no longer fully cover costs.

Previous pipeline projects have experienced significant cost escalation, which is consistent with other research on large projects (Flyvbjerg, 2017; Flyvbjerg, 2014; Gunton, 2003).[7] TMEP's capital cost forecasts have followed this trend and increased from the original estimate of $5.4 billion to $12.6 billion in an updated cost estimated provided by TM and could still increase further (Figure 6.1). The "final cost" review provided to shippers in March 2017 for confirmation of shippers' contracts set the tolls based on a previous capital cost estimate of $7.4 billion with an expected completion in late 2019 (TM, 2017).

The shippers' confirmation of the final cost estimates with TM was based on the $7.4 billion cost estimate in March 2017 (TM, 2017). This indicates the willingness of shippers to pay tolls to cover the $7.4 billion capital and operating costs of TMEP. Hence, pipeline benefits are assumed to be equal to the pipeline construction and operating costs at a $7.4 billion cost estimate for the base case. The shipping contracts confirmed by the shippers in March 2017 provide for an additional increase in tolls to cover uncapped costs, which is estimated to be 24% of the capital cost overrun (PBO, 2019, p. 11; KM, 2017). The remaining 76% of the cost overruns are covered by the pipeline owner. Therefore, although shippers assumed a capital cost of $7.4 billion when they confirmed the contracts and did not assume that costs would escalate to $12.6 billion, they were willing to incur the risk of paying 24% of any cost overruns. Therefore, we include a sensitivity analysis that assumes that the benefit of the pipeline is based on the shippers' willingness to pay tolls to cover $7.4 billion plus 24% of the cost overrun, but that any remaining cost overrun is a cost incurred by the pipeline.

The capital cost of the pipeline for the base case is assumed to be $12.6 billion, which is the most recent public estimate provided by TM (PBO, 2020). Given the propensity for costs overruns, a sensitivity analysis is included assuming a 10% increase in costs to $13.9 billion. The net benefit/cost of the pipeline is the difference between the NPV of the toll revenue based on the $7.4 billion capital cost in the final cost approval (and the sensitivity based on the $7.4 billion plus 24% of the cost overrun) and the current capital cost estimate of $12.6 billion (and the sensitivity based on a further 10% increase). The full project BCA includes the entire capital cost of $12.6 billion, while the project completion BCA includes only the forecast capital costs of completing TMEP, which are estimated to be $5.6 billion. If TMEP is shelved there are also potential salvage cost benefits, which are assumed to be $250 million (KM, 2018a).

The full project BCA base case results summarized below (Table 6.3) show that there is a net cost from pipeline operations of $4.1 billion, while the project completion BCA base case shows that there is a net benefit from pipeline operations of $1.2 billion. There are, however, the fol-

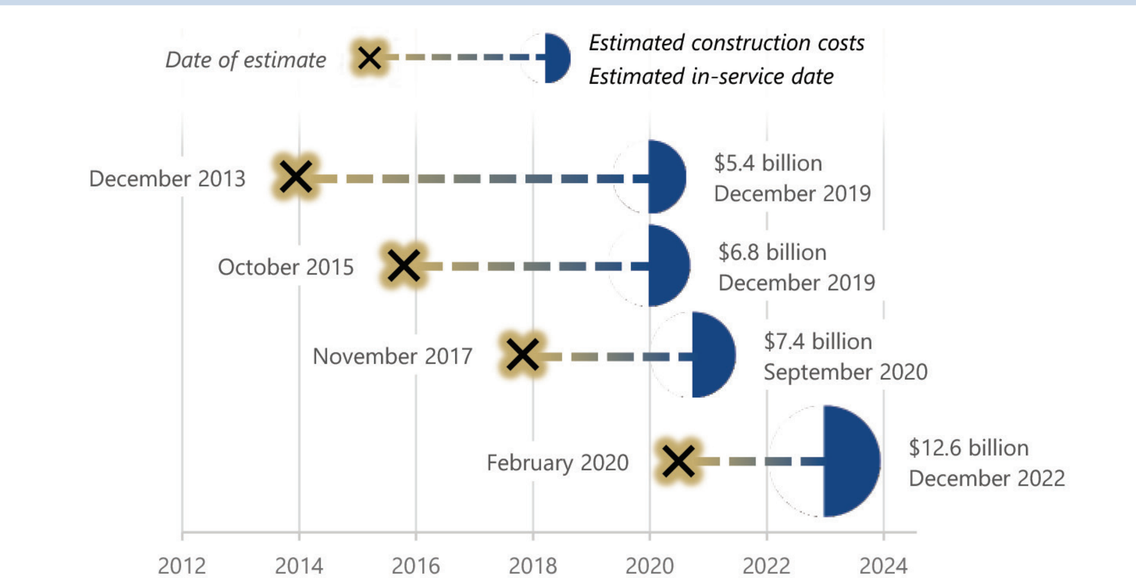
7 Estimates of the capital costs of the Enbridge Northern Gateway project increased by about one-third from $5.5 billion (2009$) ($5.9 in 2012$) as stated in its application (Enbridge, 2010) to $7.9 billion as stated in NEB Joint Review Panel Report (NEB, 2013c, p. 4). Keystone XL cost estimates increased 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.

lowing reasons why the project completion BCA pipeline benefit estimate may be lower than the estimated $1.2 billion:

- The estimated sunk costs incurred up to the end of 2020 of $7.0 billion are 55% of the TMEP total capital costs, while TM states that TMEP is 20% complete (TM, 2020c). While capital costs are not necessarily proportional to project completion, the large difference between the percent completion and the percent capital expended may indicate that sunk costs are lower than $7.0 billion and, consequently, the cost of completing the pipeline are higher. Higher completion costs would reduce the net benefit of pipeline operations below the estimated value.
- The salvage value benefit of $250 million is estimated as of July 2018 (KM, 2018a) and salvage value may be higher with the increase in capital expenditures since 2018. A higher salvage value generated if the project is stopped would offset sunk costs and reduce the net benefit estimate.
- There are additional costs not included in the final cost review approval by shippers resulting from the delay in completion date of TMEP from late 2019 to the current estimated completion date of December 2022. These costs have not been included and consequently the cost of pipeline operations could be higher than estimated in the BCA.

It should also be noted that as construction proceeds, the cost of completing the pipeline will decline and the net benefit of pipeline operations will rise with the decline in completion costs. However, the net benefit of pipeline operations will be offset by the costs of unused capacity created on other pipelines resulting from construction of TMEP. These costs of unused capacity are estimated in the next section of this report.

Figure 6.1 **TMEP Cost Estimates**



Source: PBO, 2020, p.12

Table 6.3 BCA of Pipeline Operations

Scenario	Full Project Pipeline Operation Benefits (Costs)	Project Completion Pipeline Operation Benefits (Costs)
Base Case	($4.13 billion)	$1.22 billion
Higher Construction Costs (+10%)	($5.02 billion)	$0.33 billion
Higher Tolls (covering $7.4 billion final cost estimate plus 24% of cost overruns above $7.4 billion)	($3.14 billion)	$2.14 billion

Note: Full project BCA includes all capital costs to build TMEP. Project Completion BCA includes only future capital costs to complete TMEP (total capital costs less sunk costs to end of 2020).

UNUSED TRANSPORTATION CAPACITY

There are two components to estimating the costs of surplus capacity: the quantity of unused capacity created by building TMEP and other proposed transportation projects and the cost per unit of unused capacity. We estimate the quantity of unused capacity based on our estimates of WCSB transportation capacity and oil supply summarized in Sections 4.3.2 and 4.3.3 of this report. As stated in the BCA assumptions, the base case oil supply uses the CER Evolving Scenario and the higher production sensitivity analysis uses the CER Reference Scenario. The base case WCSB oil transportation capacity assumptions include operation of all existing pipelines and under construction projects but excludes Keystone XL given that this pipeline project has been cancelled by the Biden administration. Transportation capacity is assumed to be 95% of nameplate capacity. Sensitivity analysis is conducted with high and low transportation capacity assumptions. The high senstitivty assumes Keystone XL is reapproved and constructed sometime in the future. The low sensitivity assumes that Enbridge's Southern Lights reversal does not proceed and rail capacity is not utilized.

Under all the scenarios, construction of TMEP results in surplus capacity. Under the base case CER Evolving Scenario oil supply forecast TMEP is not needed throughout the forecast period. Even under the highly unlikely CER Reference Scenario, TMEP is not required until around 2028 if Keystone XL is not built. The quantity of unused capacity used in the BCA is the lower of: (1) the 560.5kbpd diverted to TMEP (95% of the expansion capacity) and (2) total unused oil transportation capacity at 95% capacity utilization. Therefore, the surplus capacity cost estimates are only the proportion of surplus capacity costs resulting from construction of TMEP.

The second step in estimating surplus capacity costs is to estimate the cost per barrel of surplus capacity. We use two methods for estimating the per unit costs of surplus capacity. The first method we use to estimate unused capacity costs is to use the loss in net revenue on existing pipelines resulting from the diversion of oil to TMEP. Enbridge and TransCanada used this approach in NEB hearings to estimate the costs of unused capacity generated by the Enbridge Northern Gateway Pipeline (ENGP) (Wright Mansell, 2012, p. 144) and Keystone XL Pipeline (NEB, 2010b, p. 24), respectively. In this method, the cost of the unused capacity is defined as the net revenue loss per barrel of reduced shipments times reduction in shipments on other pipelines resulting from construction of TMEP. Enbridge recently estimated the net revenue loss

Table 6.4 Unused Capacity Costs Resulting from TMEP

Cost Assumption	Unused Capacity Cost ($ net present value)
Enbridge net revenue loss method	$7.4 billion
Enbridge net revenue loss method (high oil production sensitivity)	$3.8 billion
TMEP unneeded capital cost method (full project BCA with base case oil production forecast)	$10.0 billion

from reduced shipments on its pipeline system of $12 million per month per 100kbpd reduction, which translates into a $3.95 net revenue loss per barrel reduction (Enbridge, 2020, p. 31). This per barrel net revenue loss is then multiplied by the barrel reduction in shipments on Enbridge due to construction of TMEP to estimate the costs of unused capacity. Under the various supply and demand scenarios, the estimated cost of unused capacity resulting from the construction of TMEP ranges from $7.4 billion in the base case to $3.8 billion under the higher CER Reference Scenario forecast (Table 6.4).

The second method is to assume that the toll revenue received by TMEP to recover its capital costs should only be included as a benefit to Canada when the TMEP capacity is required (i.e., when 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 TMEP toll revenue is included as a benefit for only the years that the TMEP capacity is needed, while the capital costs of the TMEP are deducted in the years that the capital costs are incurred. This method results in a higher estimate ($10.0 billion) than the first method.

The unused capacity costs are borne by three parties: pipeline operators who earn lower returns due to lower shipments, oil producers who may earn lower profits due higher tolls to cover the unused capacity costs, and governments who earn lower tax revenues due to lower oil industry profits. We have not estimated the distribution of these costs among the three parties.

HIGHER NETBACKS TO OIL PRODUCERS AND OPTION VALUE

A report completed by consultants Muse Stancil (MS) on behalf of Kinder Morgan states that a major benefit of TMEP is that it will increase the prices received for Canadian oil by reducing the need to transport WCSB crude oil via higher cost rail and by reducing oil supply to the North American market (MS, 2015, p. 56). The evaluation of the MS report provided in Appendix 2 of this report identifies major flaws in the method and assumptions that MS uses to generate its forecast of increased netbacks. The evaluation shows that the MS analysis is based on incorrect assumptions regarding oil production forecasts, oil transportation capacity, and relative costs of oil transportation options. For example, the MS analysis uses an outdated capital cost estimate for TMEP of $5.4 billion, less than one-half the current cost estimate of $12.6 billion. This capital cost underestimate results in an underestimate of TMEP tolls relative to other transport options which in turn results in an erroneous estimate of the alleged benefits of TMEP. Flaws in the model include failure to account for changes in refinery capacity and failure to equilibrate oil markets to account for shifts in the geographic destination of oil shipments resulting from TMEP. The evaluation in Appendix 2 confirms the invalidity of the MS analysis by showing that Canadian oil price trends are inconsistent with the MS forecast. Therefore, the MS conclusion that TMEP will increase the netbacks for Canadian producers is unfounded.

A related argument in support of TMEP is that it will allow Canadian producers to access higher priced Asian markets. This argument is also flawed. Although price differentials for homogenous types of oil are possible due to shorter term market constraints, they are unlikely over the longer term. For example, oil prices in Asia were higher than European and US prices by up to $1.50 per barrel throughout the 1990s (Ogawa, 2003), but 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 long-term premium. Doshi and D'Souza (2011) note a 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 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. This is confirmed by a recent comparison of the prices of Mexican Maya to Asia and the US Gulf Coast (USGC). The average price received by Mexico for its Maya heavy oil was actually an average of $1.90 (US) per barrel higher in the USGC than Asia from 2010–2020 (see Appendix 2, Figure A2. 1).

The reason that long term price differentials are unlikely is because the world oil market is an integrated 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 constraints that result in temporary price differentials, the global oil market will erode these differences overtime. As the former chief executive officer for Imperial Oil observes, oil is a fungible and easily transportable product, and consequently 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). Kinder Morgan's own expert and author of the MS (2015) report concurred with this in his testimony during the NEB hearings on the ENGP by stating:

> And as you can kind of see from this chart here, I mean, millions and millions of barrels of crude are transported by waterborne — on the water around the world. And accordingly, the global crude market can pretty quickly re-equilibrate their prices. Oil prices are very high in one part of the world, you'll have more tankers starting to come into that part of the world and the price will equilibrate (Earnest, 2012, p. A47316).

Although option values generated by long-term price differentials in oil markets are highly unlikely, there may be short-term price differentials that shippers on TMEP could take advantage of from a new Pacific port.[8] Therefore, we test a scenario based on TMEP generating increased returns to producers by providing an option value based on the possibility of exploiting potentially higher priced oil markets such as Asia from a new oil port on the Pacific. The sensitivity analysis uses the average historical difference between US and Asian prices for the short-term period between 2000 and 2011 estimated by MS (2010; 2012) for the ENGP of $2.28 (2020 CDN $) per barrel of heavy crude. In the sensitivity, we assume that this price premium is received for 500kbpd of crude oil shipped on TMEP over the 17-year operating period used in the MS analysis of netbacks. The estimated benefit of this price lift from TMEP shipments to Asia is $2.3 billion net present value.

We again emphasize that this estimate of a $2.3 billion price premium benefit that may accrue from building TMEP is highly unlikely because the assumption of a long-term price premium used in the sensitivity is not evident from recent price data showing that heavy oil prices are higher in the USGC than Asia (see Figure A2. 2) and is inconsistent with the operation of the world oil market. The USGC is and will continue to be the strongest market for heavy oil in the world (IHS Markit, 2018). Consequently, if anything, it is more likely that TMEP will result in lower netbacks for producers by not accessing USGC heavy oil markets at as low a cost as other pipelines (see Table 4.3).

EMPLOYMENT BENEFITS

A potential benefit of TMEP is providing employment to workers. As discussed in Section 3.2.6 of this report, the measure of employment benefits is not the gross number of jobs generated by TMEP but is instead the net employment and income gain of employees of TMEP relative to what they would have made if TMEP did not proceed. Historically, the economy of Western Canada has been characterized by tight labour markets in which most employees are employed. Under full employment, projects like TMEP would simply draw employees from other jobs with little to no net employment benefit. However, given the current recession and recent slowdowns in the energy sector and the potential of TM training and hiring employees through impact benefit agreements, there will likely 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 the BCA.

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, which has been estimated in various studies (e.g., 5% (Wright Mansell, 2012, p. 73); 10–15% (Shaffer, 2010). In the base case we assume an employment benefit of 10% applied to

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8 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.

construction employment income. We also include a sensitivity of 15% applied to construction and operating employment income to measure the range of potential employment benefits. We use the percent of direct labour income for construction and operating employment incomes of total construction and operating costs based on data in the TMEP application, which we note is high compared to other pipeline projects and may therefore overstate the employment benefit (TM 2013a, Vol. 5B).[9] Total estimated employment benefits for TMEP range from $390 to $585 million (net present value) in the full project BCA.

BENEFITS AND COSTS TO TAXPAYERS

Incremental tax revenues not offset by incremental government expenditures are a benefit to taxpayers. As discussed earlier in Section 3.2.6 of this report, the net increase in tax revenue is significantly lower than the gross tax revenue because the gross increase includes tax revenue that would have been generated by other economic activity in the absence of TMEP being built. The gross revenue estimates also do not deduct incremental costs to government resulting from the project such as emergency response and regulatory monitoring.

In BCA it is normally assumed that most economic activity-related tax revenue (e.g., income and sales taxes) is not incremental because tax revenue would have been generated in alternative economic activity that would occur if the project did not proceed (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 TMEP there are two streams of tax revenue that could generate net benefits: royalty and corporate income tax revenue from an Asian price premium induced by the TMEP, and property tax revenue from the new pipeline and related facilities. As previously discussed, a permanent oil price benefit is highly unlikely. Nonetheless, we do include a sensitivity analysis based on the historical Asian price premium from 2000 to 2011 estimated by MS (2010; 2012). In this scenario, we include the incremental tax revenue generated by the higher oil prices as a benefit to government based on the ratios of government revenue to oil prices in the CBC report (CBC, 2015) applied to the increased netback. We estimate the net benefit of the incremental tax revenue is $1.0 billion (net present value), which is included in the overall $2.3 billion price benefit sensitivity estimate provided in section 6.4.

Secondly, although some of the property tax revenue from 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 TMEP that would not have been generated by alternative economic ac-

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9 We use total direct construction labour income (TM 2013a, 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 39%) is more than double the ratio used for employment benefit estimates in other pipeline projects such as the ENGP (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 (CBC, 2015), 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.

tivity and is not offset by increased costs generated by TMEP. 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 TMEP at $26.5 million per year (2012 $), of which $23.1 million is paid in BC and $3.4 million in Alberta (TM, 2013a, Vol. 5B p. 7–185). The net benefit of the property tax is $273 million (NPV). As discussed in the financial impact analysis there is also a reduction in corporate income tax payments resulting from oil diverted from Enbridge pipelines to TMEP due to the reduced taxable income resulting from the depreciation of TMEP assets. This reduction is included in the estimates of unused capacity costs and is not included in the tax revenue analysis to avoid double counting.

There are also a number of potential costs to governments. As discussed in Section 5.5, the government of Canada has committed to a large-scale ocean protection plan with an estimated cost of $1.5 billion (ECCC, 2018). The government has repeatedly referenced this plan as a response to TMEP specific concerns and a portion of the funding is therefore a cost to taxpayers for TMEP. The cost is to some degree offset by the mitigation benefits of reducing spill risks from TMEP and other current activities such as barge transport of oil and refined products. However, these mitigation benefits are already included in the oil spill risk costs in Section 4.9.3, which assume that this program is effectively implemented. Therefore, our government tax revenue estimates overstate incremental government revenue because we have not deducted incremental costs to government such as the mitigation costs of Canada's Oceans Protection Plan in our BCA.

A second cost is the potential for lower government tax revenue resulting from lower netbacks to oil producers due to the higher toll costs on TMEP relative to other transportation options. This is in effect the reverse of the higher netback scenario. We have not estimated this extra cost in our BCA. The government will also bear a proportion of the unused capacity costs in the form of reduced tax revenues from oil producers who may have lower profits due to higher tolls to cover the unused capacity and from pipeline operators who may have lower profits due to lower volumes of shipments earning lower. These costs to government are included in the total unused capacity costs.

COSTS TO BC HYDRO AND BC HYDRO CUSTOMERS

TM estimates that TMEP will consume approximately 1,045 gigawatt-hours (GWh) of electricity per year, 526 of which will be consumed in BC (TM, 2014, p. 110–111). Although TM will pay for the electricity, current rates in BC 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 TMEP. BC Hydro's estimated long-run incremental cost of energy is $91 per megawatt-hour (MWh) (BCUC, 2015) while the average amount paid by TM for power requirements in BC is $76 per MWh (TM, 2014, p. 110–111), resulting in a net cost to BC

Hydro of $15 per MWh, or $8 million per year.[10] The net cost to BC Hydro and BC ratepayers is $73 million (net present value). We assume that any electricity generated in Alberta to supply the project is covered by the rates that Alberta will charge TM.

ENVIRONMENTAL COSTS

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, nitrogen oxides, and particulate matter that affect human and ecosystem health. Exposure to these pollutants can cause respiratory and heart health effects and increase mortality rates in humans (IMO, 2009; US EPA, 2009). Sulphur dioxide and nitrogen oxides are also associated with acid precipitation that can affect forest and aquatic ecosystems (US EPA, 2009), and particulate matter deposition contributes to acidification and nutrient enrichment (IMO, 2009). Construction and operation of TMEP would also emit carbon monoxide, volatile organic compounds, and other hazardous air pollutants including benzene, toluene, ethyl benzene, and xylenes.

The estimate of air pollution costs is based on the damage costs per tonne of air pollutant times the quantity of tonnes released by TMEP. Air pollution damage costs estimated 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

Table 6.5 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]	Midpoint estimate used in CBA
CO	3 – 2,819	n/a	n/a	n/a	1,411
SO2	2,067 – 12,618	1,969 – 3,281	2,212 – 3,109	810 – 2,771	3,605
NOX	591 – 22,504	656	1,247 – 1,818	2,141 –2,640	4,407
PM10	2,550 – 43,492	437 – 1,094	n/a	n/a	11,893
PM2.5	n/a	2,406 – 7,218	19,650 – 28,626	5,359 – 6,830	11,681
VOC	430 – 11,813	656 – 1,094	n/a	114 – 280	2,398

Sources: Matthews and Lave (2000), Muller and Mendelsohn (2007), DEFRA (2011), Sawyer et al. (2007).

Notes: CO = carbon monoxide; SO2 = sulphur dioxide; NOX = nitrogen oxides; PM = particulate matter; VOC = volatile organic compounds. 1. All damage costs adjusted to 2020 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.

10 BC Hydro's most recent long run marginal cost estimate was completed in 2015. We have used this estimate and converted it into 2020 $. Given cost overruns on Site C, the incremental cost is likely significantly higher than the 2015 estimate.

socio-economic characteristics of impacted areas (Table 6.5). We estimate air pollution costs of TMEP using air emissions data provided by TM (TM, 2015a, p. 21; TM, 2013d, p. 200; EC, 2004) and the cost damage data summarized in Table 6.5. For the CBA we use the mid-point damage cost based on the range of costs estimated in the four studies times the quantity of pollution by year. The estimated air pollution cost is the net present value in social damage costs over the life of the project. 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.

GREENHOUSE GAS EMISSIONS

TM estimates that 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, 2013a, Vol. 8A, p. 266; TM, 2015b, p.30). Other GHG sources indirectly associated with 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 TMEP (NEB, 2013a) explicitly excluded consideration of impacts associated with upstream oil production and downstream consumption and marine emissions outside of the study area. Consistent with the NEB's directive for the TMEP hearings, we have omitted the cost of upstream and downstream GHG emissions from our analysis. However, we note that the upstream and downstream effects of oil account for approximately 99% of the GHG emissions associated with oil and hence our BCA includes only about 1% of the GHG emission costs (IHS CERA, 2010). GHG emissions associated with the production and consumption of oil transported on TMEP are a concern to many Canadians and need to be assessed at some point in the project evaluation process.[11]

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 (PCT, 2014) and the NEB (2019, p. 221) approval requires TM to offset all construction related GHG emissions. However, an 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 measures to achieve GHG reductions at approximately 30 euros per tonne (approximately $45 Canadian), while Canada's since dissolved National Roundtable on the Environment and Economy estimated prices for carbon dioxide equivalents required to achieve Canada's medium and

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11 There is uncertainty whether the new pipeline projects such as TMEP result in an increase in oil production and an associated increase in GHG emissions. Our analysis assumes that if TMEP is not built, other transportation facilities would be used in place of TMEP and therefore building TMEP does not directly result in increased oil production. GHG impacts of increased oil production are nonetheless important and should be assessed as part of an overall energy and climate change policy instead of being assessed as part of specific transportation project by project assessments.

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 $125 in 2020 $) by 2020, rising to $300 (2006 $) by 2050.

A third approach to estimating GHG damage costs is to estimate the social cost of GHG damage. In a meta-analysis of the social cost of carbon, Tol (2011) examines 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 the cost and effectiveness of offsets required for TMEP, we use the social damage cost approach based on damage costs recommended in US government guidelines, which have been adopted in Canadian government guidelines (US GAO, 2016; Canada, 2016). The 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 the US government (US GAO, 2016) recommended cost of $71 per tonne (2020 CDN $) in 2020, and for our sensitivity we use the upper range US government cost of $213 per tonne (2020 CDN $) in 2020. 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; 2016). Based on this approach, we estimate that gross GHG damage costs from the transportation of oil on TMEP (excluding upstream and downstream emissions) are between $438 million and $1.34 billion (net present value).[12]

The net GHG damage costs are between $224 million and $1.16 billion and we include in these figures the carbon taxes collected on emissions in BC and Alberta from TMEP, which partially offset the damage costs of GHG emissions. The Pan-Canadian Framework on Clean Growth and Climate Change agreed to by a majority of provinces and territories, including BC and Alberta, includes a carbon pricing benchmark rising to $50 per tonne of carbon dioxide in 2022. We assume carbon taxes are collected for emissions occurring in BC and Alberta from TMEP according to this federal benchmark, resulting in a partial offset of the damage costs associated with these GHG emissions of $224 million (net present value).

OIL SPILL DAMAGES

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

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12 A challenge in estimating the GHG impacts of 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. All GHG emissions from construction of the TMEP will be incremental. The CER conditions require TM to offset all construction emissions (NEB, 2019, P. 221). The cost and effectiveness of the offsets is unknown but is estimated in the CBA as the social damage costs times the construction generated GHG emissions.

*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 clean-up cost per volumetric or areas unit of spill (barrels or hectares); and

q is the size of the spill (in barrels or hectares).[13]

We use oil spill probability and damage costs estimates for spills based on the findings of Gunton and Joseph in their oil spill risk assessment report of the TMEP (Gunton and Joseph, 2018).[14] Gunton and Joseph (2018) estimate that the probability of a marine tanker spill for the expansion project over a 50-year operating period based on the NEB definition of the marine project area ranges between 43% and 75%, with the best estimate based on the precautionary principle being at the upper end of this range. The lower bound (43%) is based on TM's New Case 1 spill probability estimate and the upper bound (75%) is based on the US BOEM's OSRA methodology for tanker spills ≥1,000 barrels in US ports (US BOEM, 2016, p. 63–4). If Canada's proposed oil spill risk management plans are not fully and effectively implemented and/or Canada's oil spill risk management capacity is not equivalent to the US, then the upper bound probability of a tanker spill will be higher than 75%.

Tanker and Terminal Spills

The US government's oil spill risk analysis (OSRA) model is the standard method used by the US government to assess marine oil spill probabilities.[15] The US government publishes tanker and terminal oil spill rates for their OSRA model disaggregated by in-port and at sea (US BOEM, 2016). The OSRA model defines spills in-port as spills that are in close enough proximity to shorelines to impact shoreline environment. For the base case, we use the OSRA in-port spill rates to calculate the annual probability for a tanker spill of 0.031. For the base case we use the average size tanker spill of 50,313 barrels (US BOEM, 2016, p68) and the for the sensitivity we use the median size spill of 8,184 from US BOEM (2016, p. 68). While tanker spill costs based on spills that occur in-port are likely more indicative of costs incurred by Canadians since they occur in Canadian waters, these costs understate total costs associated with TMEP tanker spills because they exclude at sea spill damages. Therefore, we include a sensitivity analysis using spill rates for tanker spills that occur in-port and at sea from the OSRA model to calculate an annual probability of 0.071. We also complete a sensitivity using a lower estimate of spill probability based on TM's tanker and terminal spill probability estimates in the TMEP application (New Case 1). We note that the evaluation of oil spill risks by Gunton and Broadbent (2015) and Gunton and

13 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).

14 We provide only a brief summary of the spill probability and costs assumptions here. For more detailed background consult Gunton and Joseph (2018) for the basis of the probability and damage cost estimates.

15 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 (US BOEM, 2016).

Table 6.6 Summary of Major Marine Spill Parameters for Oil Spill Cost Estimates

	Base Case: OSRA (in-port)	Sensitivity Analysis: Higher Estimate: OSRA (in-port/at sea)	Sensitivity Analysis: Lower Estimate: TM's New Case 1
Probability of Oil Spill over 50-year Operations	75%	95%	43%
Annual Probability of Oil Spill[1]	0.031	0.071	0.011 (Tanker) 0.045 (Tanker and Terminal)[2]
Mean Size Tanker Spill (barrels)[3]	50,313	50,313	8,184
Worst Case Size Tanker Spill(barrels)[3]	103,782	103,782	103,782
Damage Cost[4]	$42,596/barrel	$42,596/barrel	$42,596/barrel (Tanker) $22,908/barrel (Terminal)
Total Damage Cost of Mean Size Tanker Spill	$2.1 billion	$2.1 billion	$0.4 billion
Total Damage Cost of Worst-Case Size Tanker Spill	$4.2 billion	$4.2 billion	$4.2 billion
Mean Size Tanker Spill Cost Used in CBA (net present expected value)	$608 million	$1,393 million	$36 million

Sources: Gunton and Broadbent (2015); Gunton and Joseph (2018); US BOEM (2016); TM (2013a, TERMPOL 3.15, 2015a; 2015b).

Notes: 1. The annual probability for the base case represents spills that occur in port estimated with the OSRA model (US BOEM, 2016), while the higher estimate represents combined in-port and at sea spills from the OSRA (US BOEM, 2016). The annual probability for TM Case 1 is just at sea spills from TM (2015a). See Gunton and Joseph (2018) for how the rates were calculated.
2. The annual probability of 0.045 for the lower sensitivity analysis scenario is the combined probability for terminal and at sea spills.
3. Tanker spill sizes of 50,313 barrels is average tanker spill size estimate from US BOEM (2016), p.68 and 8,184 barrels is the median spill size estimate from US BOEM (2016) p. 68. The credible worst-case outflow of 103,782 barrels is from TM as reported in Gunton and Joseph (2018). The credible worst case is not used in the CBA.
4. Costs are based on Wright Mansell (2012, p. 77) updated to 2020 CDN $. Estimation of spill damage costs for the sensitivity scenario sums the cost of at sea spills and terminal spill costs. Terminal spill costs are estimated by using an annual probability of 0.029 for terminal spills <63 barrels and 0.0043 for terminal spills > 63 and <629 barrels; spill damage costs for TM New Case 1 terminal spill costs based on TM's (2013a, Vol. 7 App. G p. 24) estimated cost of $20,350/barrel updated to 2020 dollars.

Joseph (2018) identify 27 deficiencies with the TM spill probability estimates, some of which result in an underestimate of spill risk. Also, TM's lower probability tanker spill estimates are significantly lower 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 6.6 presents the parameters used in our oil spill damage costing.

In their BCA of the ENGP, Wright Mansell uses two marine damage spill costs: $37,500/barrel (2012 $) for the base case and a sensitivity analysis in which they double the cost of a marine oil spill to $75,000/barrel (2012 $) (Wright Mansell, 2012, p. 93). We use their base case damage cost of spills of $37,500/barrel (2012 $) updated to $42,596 (2020 $). 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). We agree with Wright Mansell on the use of a conservative approach when examining the potential costs of oil spills.

We caution, however, that Wright Mansell's spill cost estimates may underestimate actual damage costs because they rely on studies from Kontovas et al. (2010) that estimate tanker spill cost data from the International Oil Pollution Compensation Fund (IOPCF) that 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 damage costs (Thébaud et al., 2005).[16] Second, IOPCF payments are limited by maximum payout limits set by the funds and therefore only compensate a portion of total spill damages if damages exceed the fund limits.[17] 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, 2013a, Vol. 7 App. G, p. 24). Terminal costs are only calculated for the marine spill cost estimate (New Case 1) and not the OSRA estimates because the OSRA estimates already incorporate in-port spills in the return period estimates.

Pipeline Spills

Alternative estimates for pipeline spill probabilities are summarized in Table 6.7. For our base case we use the probabilities and average size spills based on Pipeline and Hazardous Materials Safety Administration (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 pipeline spill return periods are between the return periods based on Enbridge historical spill data and the return period estimated by TM.

Estimates of pipeline spill damage costs range from approximately $3,000 to $182,000 per barrel depending on the size of spill, the type of oil, and the area impacted (Table 6.8). We use the PHMSA average spill damage cost of about $15,000/barrel (weighted average of ruptures and leaks) which is in the mid-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, 2014a; PHMSA, 2014b). This results in an average cost per pipeline spill in our BCA of $4.0 million, which is then used to estimate the annual expected value of a spill by multiplying the cost times the annual probability.

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16 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%.

17 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 6.7 Comparison of Pipeline Spill Risk Estimates for TMEP Line 2

Source of Spill Rates	Size and Type of Spill	Return Period (years)[1]
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 540kbpd of the 590kbpd 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.

Table 6.8 Summary of Alternative Spill Cost Estimates per Barrel for Pipelines

Type of Spill	TMEP Application	BOSCEM	PHMSA 2010–2014	Enbridge Line 6B	ENGP Application
Leak	\$30,776 – \$94,696	\$13,841 – \$182,313	\$3,474	n/a	\$10,991
Rupture	\$7,101 – \$17,665	\$3,294 – \$53,260	\$33,521	\$65,599	\$13,457

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

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 costs are 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 acknowledge that to the extent that toll costs include insurance premiums to cover oil spill damage costs, the costs of TMEP pipeline spills are to some degree already incorporated in the costs of pipeline operations. Also reduced shipments on other pipelines resulting from building TMEP may lower oil spill risk on other pipelines thus to some degree offsetting the oil spill risk costs from TMEP.[18]

18 Estimating the reduction in spill risk and spill damage resulting from reduced shipment on existing transportation facilities is challenging because spill risk and spill damage is a function of the volume shipped, length of the pipeline system, and the location impacted. Diverting volumes will reduce the volume shipped in existing transportation facilities but will not change the length of the pipeline system and thus will not have a proportional impact on spill rates.

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 use 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 TMEP, First Nations and 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. TM did not undertake this type of contingent valuation study for TMEP.

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., 2017; Johnston et al., 2018). 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; Johnston et al., 2018).

We estimate potential passive use values for marine oil spill risk for 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 et al. (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.[19] 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.[20] The Carson studies are among the most sophisticated contingent valuation studies for assessing passive use values.[21]

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

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19 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).

20 Carson et al. (2004) do not define the volume of oil spilled in the California oil spill study. 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.

21 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.

Table 6.9 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 recovery 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).

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.[22] 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 6.9).

While undertaking a contingent valuation study specifically for 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 TMEP because the Carson studies use best practices methods, assess 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 a change that is perceived as a loss tends to be valued more highly than one's WTP to prevent the loss (Rutherford et al., 1998; Horowitz and McConnell, 2002; Knetsch, 2005, 2020). 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. In another meta-analysis, Tuncel and Hammitt (2014) found that that WTA values were on average 6.23 times higher than WTP values for environmental 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, 2020; Zerbe and Bellas, 2006; Shaffer, 2010). Unlike private goods defined

22 EVOS estimates are $60 and $89 in 1995$.

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, 2020). However, in the case of increasing oil spill risk, Carson et al. (2003) and Knetsch (2020) 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) and Knetsch (2020) 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 for which they are being asked to pay.

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 to BC 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 TMEP tanker spill risk we use the upper and lower bound of the 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 2020 CDN $) by the total number of households in Canada.[23] To provide an order of magnitude estimate of potential WTA values we adjust the midpoint WTP estimate with the WTA/WTP ratio of 6.23 for environmental goods derived from a meta-analysis of WTA/WTP ratios by Tuncel and Hammitt (2014) and multiply it by the total number of BC households.

The estimates of the risk of marine spills to passive use value range from a low of $1.9 billion based on WTP for Canadian households to a high of $17.4 billion based on WTA for Canadian

23 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 2016 from Statistics Canada data.

Table 6.10 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	$1,892 – $2,796
WTA Canadian households	$11,787 – $17,419
WTA BC households	$1,953

households (Table 6. 10). Given the challenges involved in extrapolating the passive use costs to the entire Canadian population, we have used a conservative estimate of WTA for BC households of $1,953 million in our CBA. Consequently, passive use damages are likely much higher than our estimate based on the BC population only.

There are several qualifications with respect to our estimates of passive use value damages of TMEP that should be noted. First, the calculations of passive use reflect the values 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 from a spill in BC differently than Americans value Alaskan spill damages. 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 Tuncel and Hammitt (2014) 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. (2003) study was also done following a major oil spill and the *ex post* WTP for 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. For these reasons, our estimates of passive use damages values should be viewed as only illustrative of the potential order of magnitude of passive use damages.

Another issue that has been raised by TM (2015c) 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 for 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 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 on the Carson study. 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.

A final 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. Consequently, transferring estimates of passive use damage costs from oil spills from the Carson studies to the TMEP case should not lead to double counting.

We note that the inclusion of passive use values in BCA is sometimes considered controversial. For example, the NEB (2016, p. 407) report on TMEP rejected marine oil spill damage costs that included passive use values costs on the grounds that such costs are "overly hypothetical". The NEB's conclusion is inconsistent with accepted practice in BCA. For example, even project proponents such as Enbridge accept the validity of passive use values in their applications (Wright Mansell, 2012, p. 106–9). Nonetheless, given the controversy over passive values, we do not include them in our base case results, but we show the WTA for BC households in our sensitivity analysis.

DAMAGES TO OTHER ECOSYSTEM GOODS AND SERVICES

TMEP would cause damages to a variety of other ecosystem goods and services not already covered in previous subsections 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, 2013a, Vol. 5). A BCA (Broadbent, 2014) for the ENGP estimated terrestrial ecosystem goods and services losses to be in the range of $8 million to $707 million net present value (2012$), indicating that losses of ecosystem goods and services from pipeline construction alone can be significant. We do not provide an estimate of these damage costs for TMEP due to data limitations and thus our environmental damage cost estimates may underestimate the total costs of TMEP.

OTHER COSTS

In Appendix 1, we list 160 negative impacts associated with TMEP of which only a few are monetized for our BCA 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 BCA (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 TMEP due to omission of these other adverse impacts.

IMPACTS ON FIRST NATIONS FROM OIL SPILLS

The importance of environmental valuation for First Nations is 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 liquid natural gas (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 (2014 $) per member of the First Nation.[24] The Nation rejected the offer on the grounds that the project would affect salmon habitat and have unacceptable 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).

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

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24 According to the federal government, the Lax Kw'alaams First Nation has a total registered population of 3,733 (AANDC, n.d.). 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.

purposes. Fishing for food, social, and ceremonial purposes is a defining cultural practice of the traditional 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).

CONFLICT AND OPPOSITION

Another potential social cost that is difficult to value monetarily is the cost of major conflict over the building of TMEP as a result of opposition to the project. Polls show strong opposition to major pipeline projects in BC. Many interveners including the City of Vancouver, the City of Burnaby, and some First Nations are opposed to TMEP and there have been demonstrations against TMEP. The ongoing conflict over TMEP 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. None of these costs are included as monetary values in our BCA and consequently, the costs of TMEP are underestimated.

BENEFIT COST ANALYSIS RESULTS

Our multiple account BCA results are summarized in Table 6. 11 and Table 6. 12. The results of the full project BCA for the base case (Table 6. 11) show that building TMEP will result in a *net cost to Canada of $11.9 billion*. A large component of the cost is the cost of unused capacity of $7.4 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.[25] Again, it is important to emphasize that this unused cost estimate assumes that Keystone XL is not built. 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 replaced by taxes generated in alternative economic activity if TMEP is not built. Environmental costs are significant ($961 million), comprising $224 million for GHG emissions, $110 million for other air pollution, and $627 million for oil spills. Including passive use damages, environmental costs total $2.9 billion.

The results of our sensitivity analyses (Table 6. 12) show that building TMEP results in a net cost to Canada under all scenarios, ranging between costs of *$8.3 billion and $18.5 billion*. The highest net cost of $18.5 billion is based on a lower discount rate of 3%. The lowest net cost of $8.3 billion is based on the unlikely higher CER Reference Scenario oil supply forecast, which assumes that no new measures to combat climate change are implemented. The assumption of an Asian price premium generates a benefit, but even with this option value benefit, TMEP still results in an overall net cost of $9.6 billion. The BCA results show that there is no likely scenario in which the decision to build TMEP would result in a net benefit to Canada.

The project completion BCA results are based on evaluating a partially completed project and omit sunk costs incurred and benefits received up to the end of 2020. These results are relevant to evaluating whether it is worth continuing construction on TMEP now that the project is partially built. The BCA shows that completing the TMEP still results in a significant *net cost* of $6.8 billion, and there is a *net cost* under all likely scenarios ranging from $3.2 billion to $13.3 billion. As construction progresses, the net costs of completing TMEP will continue to decline. However, completing TMEP will result in a net cost regardless of the stage of completion because incremental capital expenditures on TMEP do not generate incremental benefits. TMEP capacity is excess to Canadian needs and the oil shipped on TMEP could be shipped on other pipelines. The earlier TMEP construction is curtailed, the greater the savings, but there will still be savings regardless of when construction stops.

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25 The distribution of unused capacity costs among various parties and governments 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.

Table 6.11 Benefit Cost Analysis Results for TMEP

Item	Net Benefit (Cost), Base Case (million $)	Sensitivity Analysis Range (million $)[1]
TMEP Pipeline Operations	(4,131)	(5,023) to (3,139)
Unused Oil Transportation Capacity	(7,401)	(7,401) to (3,796)
Option Value/Oil Price Netback Increase	0	0 to 2,293
Employment	390	390 to 585
Tax Revenue	273	273 to 1,305
Electricity	(73)	No sensitivity
GHG Emissions from Construction and Operation of TMEP and Marine Traffic in Defined Study Area	(224)	(1,163) to (224)
Other Air Emissions	(110)	No sensitivity
Oil Spills	(627)	(1,412) to (55)
Passive Use Damages from Oil Spill	0	(1,953) to 0
Other Socio Economic, Environmental Costs not estimated	See Appendix 1	
Net Cost of Full Project	**(11,903)**	**(18,499) to (8,298)**
Net Cost of Project Completion (including only capital costs required to complete TMEP)	**(6,769)**	**(13,327) to (3,164)**

Note: Based on sensitivity scenarios summarized in Table 6. 2 and Table 6. 12

An obvious question is if TMEP results in a net cost to Canada, why would it be built? The explanation is based on market failures. Oil producers signed long-term contracts to ship on TMEP when oil markets were stronger, and these contracts can provide revenue for TMEP that will allow it to be built even though it is not needed. Oil producers will meet their contractual commitments to ship on TMEP by diverting oil that would otherwise be shipped on existing pipelines that are not under contract. Therefore, the costs of building TMEP will be "externality costs" shifted to other parties in the form of revenue losses borne by other pipelines as well as environmental costs borne by the public.

We note that the BCA results for TMEP are very much a function of the fact that TMEP will contribute to excess transportation capacity and the supposition that 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 transportation capacity will affect WCSB production. In this case, a BCA of new transportation projects should 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.

Table 6.12 **TMEP BCA Sensitivity Analysis Results**

Scenario	Description	Net Benefit (Cost) (million $)	Change from Base Case (million $)
Base Case		(11,903)	
TMEP Pipeline	Tolls set to cover $7.4 billion capital cost and all uncapped capital cost overruns (estimated at 24% of costs above $7.4 billion)	(10,912)	991
	10% capital cost overrun	(12,796)	(893)
Unused Capacity Costs	Unused capacity based on TMEP unused capital cost method (base case WCSB oil supply & demand conditions)	(14,512)	(2,608)
	CER Reference Scenario oil supply; w/ Keystone XL	(11,844)	59
	CER Evolving Scenario oil supply; w/ Keystone XL	(11,903)	0
	CER Reference Scenario oil supply; No Keystone XL	(8,298)	3,605
	CER Evolving Scenario oil supply; no rail, no Southern Lights Reversal	(11,617)	286
Option Value/ Oil Price Netback Increase	Average historical Asian premium estimated by MS (2010; 2012) from 2000–11 applied to 500kbpd shipped on TMEP until 2039	(9,610)	2,293
Higher Employment Benefit	15% of construction and operating employment	(11,708)	195
Tax Revenue	Property tax revenue plus royalty and income tax revenue from a price premium induced by TMEP	(10,871)	1,032
GHG Emissions	Higher social damage costs per unit	(12,842)	(939)
Oil Spills	Higher spill probability (OSRA in port/at sea tanker spill probability of 0.071x)	(12,688)	(785)
	Lower damage estimate (TM tanker spill probability of 0.011 and lower spill size)	(11,331)	572
Passive Use Damages	WTA oil spill damage for BC households	(13,856)	(1,953)
Discount Rate	10%	(10,609)	1,294
	3%	(18,499)	(6,595)
	Dual Discount (3% for environmental/health impacts; 8% for all other)	(12,635)	(731)

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 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 production forecasts will reduce unused capacity while lower oil production forecasts will increase unused capacity. We have addressed this uncertainty by using the two CER WCSB oil export forecasts; the Evolving Scenario in our base case and the Reference Scenario for a sensitivity analysis. The results show that under both of these oil supply scenarios there is a high unused capacity cost (Table 6.11). Given Canada's recent climate plan announcement, the Reference Scenario oil production forecast that assumes no new climate change measures is highly unlikely and the Evolving Scenario production forecast that assumes weaker climate policy measures than announced in the climate plan may also be too high. Therefore, the risks are that the WCSB oil production may be lower than forecast and unused capacity costs higher. There is little to no risk that WCSB will be higher than the CER forecasts.

A second variable impacting our estimate of unused capacity costs is the magnitude of existing and proposed transportation projects. There is uncertainty in the projects that will be built, and their completion dates and capacity may therefore be lower or higher than forecast, resulting in lower or higher unused capacity estimates. We have addressed this uncertainty by using 95% of nameplate capacity in our supply and demand analysis. Also, we have tested the impact of different transportation capacity including a lower capacity scenario that assumes there is no rail and Enbridge's Southern Light Reversal does not proceed. The lower transportation scenario has little impact on the net cost results, reducing net costs from $11.9 billion to $11.6 billion. As the supply and demand analysis shows, there is still about 350,000bpd of excess capacity in 2030 without TMEP and Keystone XL, so there would still be sufficient capacity even if some of the proposed projects do not proceed and if there was no rail transport (Appendix 4).

We acknowledge that some unused capacity resulting from construction of large, new pipeline projects is inevitable and can be beneficial in terms of providing flexibility in the transportation system. However, the magnitude of potential unused capacity in the Canadian oil transportation sector will be unusually high if all proposed projects are built and our BCA shows that the cost is not offset by the option value of accessing higher priced markets. It is also possible, though unlikely, 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, which could result in reduced returns on Canadian oil. However, if there is higher than forecast production and/or lower than forecast capacity additions, there will be sufficient lead time to assess and accommodate these unanticipated changes to avoid any longer term shutting in of production.[26] There is, for example, surplus rail capacity that can respond relatively quickly to changes in demand and our rail use assumption is well below rail capacity (Table 4.2). If, on the other hand, unneeded expensive pipeline facilities are built, the costs of the unused capacity are sunk costs that 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 keep options open by deferring irreversible investments in new pipelines that cannot be justified by forecast demand. We also reiterate that when and if demand justifies new capacity, the new capacity should be subject to a comprehensive benefit cost analysis.

Another important cost parameter in our BCA is environmental costs. Accurately estimating environmental costs is challenging. Many environmental impacts of TMEP are not included in our benefit cost estimates because they are difficult to estimate in dollar terms (see Appendix 1). Inclusion of these impacts would increase our environmental cost estimates and the net cost of TMEP. There are also environmental costs of shipping oil on other transportation facilities that could to some extent offset some of the environmental costs associated with TMEP. We have not included potential avoided environmental costs on other transportation facilities in our BCA and inclusion of avoided costs would reduce our environmental cost estimates. We have also omitted all environmental costs associated with the upstream production of oil consistent with our assumption that TMEP will not result in any incremental oil production. Upstream costs, however, should be assessed as part of a more comprehensive cumulative impact assessment.

Estimating the costs of oil spill damages is also challenging. 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. 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 damage 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 than spills in many other areas due to its high value environment (WSP, 2014). 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 person) to approve an 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 BCA studies, including ours, significantly underestimate environmental protection values.

A final area of uncertainty is the cost of project construction. The costs of building TMEP have escalated from the original estimate of $5.4 billion to the current estimate of $12.6 billion (PBO, 2020) and the costs could escalate further, particularly with the impacts of the pandemic. The project completion BCA also requires an estimate of incremental costs going

26 There can be short term constraints such as the current period (late 2018 and early 2019) in which transportation capacity is constrained and some reduction in production is warranted, but these periods are short term and disappear when new transportation capacity becomes available. Rail, for example, can respond relatively quickly to meet shorter term needs.

forward. The completion costs used in the BCA are as of the end of 2020. However, the completion cost estimates as of December 31, 2020 are likely on the low side given that sunk costs are estimated to be 55% of total costs, which is considerably higher that the estimated project completion of 20%, and total construction costs are likely to be higher than the current estimate of $12.6 billion. Salvage benefits from terminating construction may also be higher than estimated. For these reasons, the net project completion costs are likely to be higher than the $6.8 billion estimate.

7. Conclusion

The Government of Canada has not provided a public evaluation of its decision to purchase TM and build TMEP. Given the magnitude of its investment in TMEP, the Government has a fiduciary obligation to provide the Canadian public with a comprehensive evaluation of this investment before proceeding. The only public evaluations available are the NEB reports (2016; 2019) completed under the *NEBA* and *CEAA*. The NEB reports do not address the economic feasibility of the government's investment and are based on deficient methodology and outdated information that does not take into account material changes that have occurred since the completion of the reports including rising construction costs, weakening oil markets, and development of other transportation options. These changes adversely affect the rationale and economic viability of TMEP and their impact on the prudence of proceeding with TMEP needs to be assessed.

The purpose of this report is to address this need for public accountability by providing an independent evaluation of Government's decision to purchase Trans Mountain and build the Trans Mountain Expansion Project.

The financial impact analysis of the Government of Canada's purchase and construction of TMEP shows that the Government will incur a *net loss* under base case assumptions of *$4.8 billion* if the government sells the expanded pipeline system once TMEP is in-service. The financial impacts under alternative scenarios and assumptions range from a loss of $2.1 billion to a loss of $6.9 billion. Additional costs to the government include reduced corporate income tax revenues and increased spending on programs, such as the Oceans Protection Plan, which mitigate adverse impacts of TMEP.

The BCA, which goes beyond the narrower financial impact assessment by including all benefits and costs to Canada, shows that the decision to build TMEP will result in a *net cost* to Canada under base case assumptions of *$11.9 billion*. The net cost estimates range between $8.3 billion and $18.5 billion. There is uncertainty regarding construction costs, transportation options, and oil production forecasts. Different assumptions reflecting this uncertainty were tested and the conclusion is that there is no likely scenario in which TMEP will generate a net benefit to Canada. The project completion BCA, which assesses the costs and benefits of completing TMEP by using only future capital costs from January 1, 2021 onward, shows that completing TMEP will result in *net cost* to Canada under base case assumptions of *$6.8 billion*. The net cost estimates range between $3.2 billion and $13.3 billion. The net costs of completing the TMEP are lower than the net costs of the full project because they omit the capital costs already expended. However, the results still show that continuing to build TMEP will result in a net cost to Canada because the TMEP capacity is not required and therefore does not generate a benefit. Oil transported on TMEP could have been transported on other pipelines without expending funds building TMEP. Therefore, continuing to build TMEP as currently proposed is not in Canada's public interest and the project should not proceed further.

If and when the new oil transportation capacity is required, proposed projects should be evaluated as part of 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 public interest.

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Appendix 1: Potential Adverse Impacts of TMEP

The following table lists potential adverse impacts of building and operating TMEP that are Identified in the TMEP application.

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 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

Human Occupancy and Resource Use (Con't)	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 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
	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.	Reduced labour availability for other regional industries due to workers taking TMEP-related employment opportunities
	54.	Disruption to business or commercial establishments in the form of reduced income
	55.	Disruption to resource-based income or livelihoods

Human Health	56. Effects on mental well-being from demographic changes, changes in income, and changes to culture 57. Effects on alcohol and drug misuse 58. Increase in demand on mental health and addictions services 59. Increase in number of sexually transmitted infections 60. Increase in number of respiratory or gastrointestinal illnesses 61. Increase in stress and anxiety related to perceived contamination 62. Increase in traffic-related injury and mortality 63. Increased demand on hospitals, health care facilities, and emergency medical response services 64. Effects on diet and nutritional outcomes 65. Effects on mental well-being in Aboriginal communities
Marine Resource Use	66. Disruption to marine access and use patterns during construction and operations 67. Alteration of subsistence resources 68. Disturbance to cultural sites including sensory disturbance from noise, air emissions, lighting, and visual during construction and operations 69. Sensory disturbance for commercial, recreation, and tourism users (e.g., noise, lighting, visual, air quality) during construction and operation 70. Change in distribution and abundance of harvested species including marine fish and fish habitat 71. Displacement of commercial, recreational and tourism users around Westridge Marine Terminal during construction and operations 72. Change in commercial, recreational and tourism vessel access routes during construction and operations 73. Disruption to subsistence hunting, fishing, and plant gathering activities 74. Disruption to use of travel ways by traditional marine resource users 75. Disturbance to gathering places including increased sensory disturbance for marine users 76. Disturbance to sacred sites 77. Disruption to commercial fishing activities 78. Sensory disturbance (e.g., noise, visual effect, air quality) for commercial fishers, recreational users, and tourism users 79. Change in distribution and abundance of target species for commercial fishers 80. Alteration of existing movement patterns of marine commercial, recreational, and tourism users 81. Increased rail bridge operations 82. Marine vessels collision with built infrastructure, marine facilities or shoreline with a commercial, recreational, or tourism use 83. Marine vessel collisions with marine commercial users, other recreational users, and marine tourism users 84. Marine vessel wake effects on small fishing vessels, recreational vessels and tourism operator vessels 85. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Accidents and Malfunctions (terrestrial and marine)	86. Spills of hazardous materials during construction and maintenance potentially resulting in contamination or alteration of surface or groundwater 87. Fires that may adversely affect adjacent property 88. Damage to utility lines that could interrupt services and lead to fires 89. Transportation accidents that could cause injury to people or result in a fire 90. Use of explosives that could cause injury from flying rock 91. Security risk including damage from criminal activity

Accidents and Malfunctions (terrestrial and marine) (Con't)	92. Change in marine water quality from an accidental release of contaminated bilge water 93. Physical contact between a tanker's hull and marine subtidal habitat from vessel grounding 94. Interference with navigation from a vessel grounding 95. Physical injury or mortality of a marine mammal due to a vessel strike 96. Venting of tanker at anchor or in transit 97. Negative recreational and tourism user perspectives of increased project-related marine vessel traffic
Physical Environment	98. Terrain instability due to slumping at watercourse crossings and sidehill terrain 99. Alteration of topography along steep slopes, slopes of watercourse crossings, sidehill terrain, and areas of blasting 100. Acid generation or metal leaching rock
Soil and Soil Productivity	101. Decreased topsoil/root zone material productivity during topsoil/root zone material salvaging 102. 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 subsoils 103. 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) 104. Degradation of soil structure due to compaction, rutting, and pulverization of soil and sod 105. Loss of topsoil/root zone material through wind and water erosion 106. Erosion of soil as a result of release of hydrostatic test water on land 107. Loss of topsoil/root zone material from disturbance (e.g., maintenance dig activities) during operations 108. Increased stoniness in surface horizons 109. Bedrock or large rocks within trench depth 110. Disturbance of previously contaminated soil 111. Contamination of soil as a result of release of hydrostatic test water on land 112. Soil contamination due to spot spills during construction
Water Quality and Quantity	113. Instability of trench at locations with high water table 114. Suspended sediment concentrations in the water column during instream activities 115. Erosion from approach slopes 116. Inadvertent instream drilling mud release 117. Alteration or contamination of aquatic environment as a result of withdrawal and release of hydrostatic test water 118. Reduction of surface water quality due to small spill during construction or site-specific maintenance activities 119. Alteration of natural surface drainage patterns 120. Disruption or alteration of streamflow 121. Shallow groundwater with existing contamination encountered during trench construction 122. Areas susceptible to drilling mud release during trenchless crossing construction, sedimentation in the aquifer, and blasting effects 123. Areas with potential artesian conditions 124. Aquifers (including unconfined aquifers) or wells vulnerable to possible future contamination from a spill during construction 125. Areas susceptible to changes in groundwater flow patterns

Water Quality and Quantity (Con't)	126. Disruption of shallow groundwater in high permeable materials in proximity to rivers or watercourse crossings with fluvial materials or colluvium in the substrate 127. Disruption of groundwater flow where springs and shallow groundwater are encountered 128. Areas where dewatering may be necessary during pipeline construction activities 129. Impacts to shallow wells
Air Emissions	130. Project contribution to emissions: increase in air emissions during construction and increase in air emissions during site-specific maintenance and inspection activities 131. Dust and smoke during construction
GHG Emissions	132. Increase in carbon dioxide-equivalent emissions 133. Changes in environmental parameters (e.g., increase in global average temperature)
Acoustic Environment	134. Changes in sound level during construction and operation 135. Changes in vibrations during construction and operation
Fish and Fish Habitat	136. Riparian and instream habitat loss or alteration during construction, maintenance, and operation activities 137. Riparian and instream habitat loss or alteration from accidental drilling mud release 138. Contamination from spills during construction and maintenance 139. Increased access to instream habitat during operation 140. Fish mortality or injury during construction 141. Fish mortality or injury due to accidental release of hazardous materials during power line construction 142. Increased suspended sediment concentrations in the water column during instream construction or from accidental mud release 143. Increased access to fish and fish habitat during operations 144. Blockage of fish movements 145. Effects on fish species of concern 146. 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	147. Loss or alteration of wetlands of High Functional, High-Moderate, Low-Moderate and Low Functional Condition (i.e., habitat, hydrology, biogeochemistry) 148. Contamination of wetland function (i.e., habitat, hydrology, biogeochemistry) due to a spill during construction
Vegetation	149. 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 150. Weed introduction and spread
Wildlife and Wildlife Habitat	151. 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	152. Change in sediment quality during construction 153. Change in water quality during construction or operations

Marine Fish and Fish Habitat	154.	Loss of marine riparian, intertidal, and subtidal habitat
	155.	Decrease in productive capacity of suitable habitat, injury, or mortality of Dungeness Crab
	156.	Decrease in productive capacity of suitable habitat, injury, or mortality of inshore rockfish
	157.	Decrease in productive capacity of suitable habitat, injury, or mortality of Pacific salmon
Marine Mammals	158.	Permanent or temporary auditory injury and sensory disturbance of Harbour Seals, Southern resident Killer Whale, Humpback Whale, and Stellar Sea Lion
	159.	Injury or mortality due to vessel strikes
Marine Birds	160.	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

Source: TM, 2013a

Appendix 2: Deficiencies in Muse Stancil Assessment of Oil Price Netbacks for TMEP

Muse Stancil, consultants to TM, estimate that TMEP will increase netbacks for Canadian crude oil producers by $73.5 billion over the project's 20-year operating period (MS, 2015). These benefits would result from: (1) a reduction in oil transportation costs with TMEP as compared to rail shipping costs to the USGC; and (2) an increase in oil prices resulting from the reduction in supply of Canadian exports to the US market. We evaluated the MS study and conclude that the netback benefit estimates by MS are invalid because the assumptions are outdated and inaccurate (Table A2. 1) and the method used to estimate the netbacks is flawed.

Inaccurate and Outdated Assumptions

The first inaccurate assumption of the MS report is the quantity of pipeline capacity. MS assumed that WCSB pipeline capacity would increase by 960bpd, comprised of TMEP and Enbridge Line 3. However, current estimates are that pipeline capacity will increase by 2,590kbpd if Keystone XL is reapproved and 1,760kbpd if Keystone is not constructed. Secondly, MS's oil production forecast and oil prices assumptions used in the analysis are significantly higher than current forecasts. Based on its outdated pipeline and oil production assumptions, MS incorrectly forecasts that there would be insufficient pipeline space without TMEP and consequently WCSB oil would have to be shipped by higher cost rail to the US Gulf. According to MS, this shortage of pipeline space and reliance on higher cost rail would result in lower netbacks for Canadian producers. But as the supply/demand analysis in this report shows (see Figure 4.5), there will be sufficient pipeline capacity to accommodate WCSB demand and there will be no need to rely on higher cost rail shipments to the US Gulf during the forecast period. The higher oil price netbacks estimated by MS as a benefit of TMEP based on the assumption of the need to use rail are therefore incorrect.

The second inaccurate assumption of the MS analysis is the $5.4 billion estimated capital cost of building TMEP, which is less than one-half the current estimate of $12.6 billion (TM, 2020).

Table A2.1 Major Updates to Muse Stancil (2015) Report Assumptions

Variable	MS Assumptions	Updated Estimates
TMEP Capital Cost	$5.4 billion	$12.6 billion
WTI Oil Prices (US $/b)	$79	$51 forecast (CER Evolving Scenario)
WCSB Supply Forecast 2030 (kbpd)	6,058	4,745 (CER Evolving) – 5,373 (CER Reference)
TMEP tolls (Can. $/b) to Westridge dock heavy committed 2023	$5.19	$7.39 – $10.16
New Pipeline Capacity (kbpd)	960 (TMEP, Enbridge Line 3)	1,640 – 2,470 (see Table 4. 2)

MS's (2015, p.61) estimate of tolls of $5.19 per barrel (2018 Can $) for heavy oil delivered to the Westridge loading terminal in 2023 (the current estimated commencement of TMEP shipments) based on the $5.4 billion cost is therefore no longer valid. With the increase in capital costs to $12.6 billion, tolls will now be significantly higher, and the netbacks will be lower.

The third inaccurate assumption in the MS report is that diversification to growing Asian markets will increase netbacks for Canadian producers because of higher Asian oil prices. This assumption by MS is incorrect because it is based on a flawed model of how oil markets work and current market conditions. Although price differentials for similar grades of oil are possible due to shorter-term market constraints, they are unlikely over the longer term because the world oil market is an integrated 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).

Further, although short term price differentials may exist, the evidence shows that there is no consistent pattern favouring Asian markets over US markets. Oil prices in Asia were higher than European and US prices by up to $1.50 per barrel throughout the 1990s (Ogawa, 2003), but price differentials between Asia and the US 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 long-term premium. Doshi and D'Souza (2011) note that Asian prices were actually lower between 2007 and 2009 and Cui and Pleven (2010) suggest that Asia's diversification of crude oil supplies beyond the Middle East and Asia's increased bargaining power will eliminate any premium on Asian prices. The US Gulf, meanwhile, remains the largest market for heavy oil in the world and with the reduction in supply of heavy oil from Venezuela, the demand and prices for Canadian heavy oil in the US Gulf will remain strong (IHS, 2018). This is confirmed by a recent comparison of the benchmark prices of Mexican Maya to Asia and the US Gulf that shows that the average price received by Mexico for its Maya heavy oil was actually $1.90 (US $) per barrel higher in the US Gulf than Asia from 2010–2020 (Figure A2.1).

Figure A2.1 **Maya Heavy Oil Price Differential Between US Gulf Coast and Asia (2010-2020)**

Source: Penmex, 2019; 2020

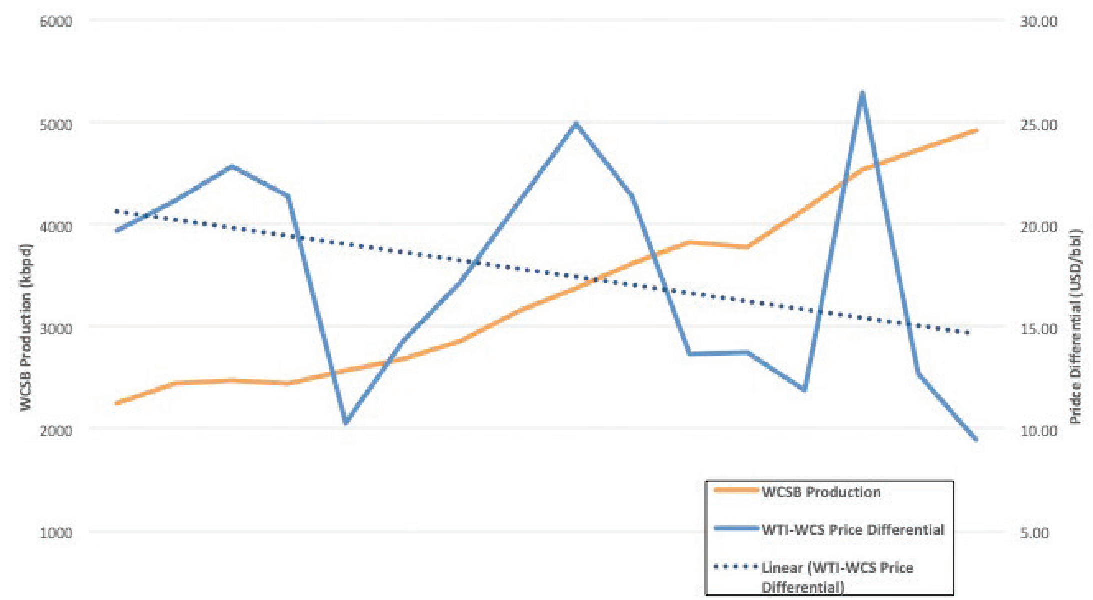
Notes: 2020 is based on the January to May average from Penmex (2020)

Flawed Methodology

In addition to inaccurate assumptions, the MS analysis has a number of methodological flaws that invalidate the results. First, the static linear programming model used by MS does not incorporate any adjustments in oil markets that would occur if WCSB exports to the US are reduced by TMEP. MS states, "[c]onsequently, about 79,500 m3/d (500 kb/d) of crude oil is going overseas (including Hawaii), which reduces the volume of Canadian crude oil that must be consumed in the North American market by the same amount. It is a fundamental economic principle that reducing the supply of a commodity, all else equal, will increase its price." (MS, 2015, p. 10). But the problem with this analysis is that all else is not equal. If TMEP redirects oil from the US to Asian markets, this will create a shortfall in the US and a surplus in Asia. Other suppliers will respond to this by redirecting shipments from Asia to the US to restore equilibrium in the market. The reduction in Canadian shipments to the US will not therefore result in an increase in US prices for Canadian oil exports because the reduction in Canadian supply will be made up by other non-Canadian suppliers. MS's static model does not allow for these market adjustments and consequently the results forecasting a higher price from reduced shipments to the US are incorrect.

A second flaw is that MS static model does not incorporate any changes in refinery demand over the entire forecast period to 2038. Given the propensity of refineries to adjust to changing market conditions (e.g., reconfiguration of some US refineries to refine more heavy oil), MS's assumption of no change in refinery demand is unfounded.

Figure A2.2 **Comparison of WCSB Production to WTI and WCS Oil Price Differentials (2005-2020)**



Sources: WCSB production is from CER (2019b). WTI and WCS Prices are from McDaniel & Associates (2017, 2020)

Notes: Correlation coefficient of -0.3065 estimated based on the correlation of WCSB production to the price differential between WTI and WSC

A third flaw in the MS model is the marginal cost pricing assumption that the price of all Canadian oil is determined by the price received by the marginal (highest cost) barrel of Canadian oil exported to the US. MS states that the marginal barrel of Canadian oil receives a lower price without TMEP because of the increased supply to the US. However, MS also assumes that the price for oil in the US is unaffected by TMEP. These two assumptions are inconsistent. If US oil prices are the same with and without TMEP, Canadian shippers will get the same US price for their oil regardless of whether TMEP is built or not. The only circumstances in which Canadian oil prices would be affected is if there are impediments to market adjustments such as inadequate transportation capacity to get Canadian oil to markets. As the supply and demand analysis shows, while this transportation constraint has occurred in the past, it is unlikely to occur in the future and hence Canadian oil should receive the world price with adjustments for differences in quality and transportation costs to market destinations.

The flaws in the MS modeling can be illustrated by empirical testing of the MS hypothesis that increased Canadian exports to the US will reduce Canadian oil prices. To test MS's hypothesis, WCSB production and the price differential between Canadian oil and international prices is plotted over the last 15 years (2005–2020) to see if higher Canadian shipments to the US result in lower prices (Figure A2. 2). During this period, WCSB production and exports to the US increased by approximately 2.5 million bpd. If MS's hypothesis is correct, the price discount measured by the difference between Canadian oil prices relative to international prices should increase as Canadian exports to the US rise.

The results in Figure A2.2 show that the price differential between Canadian oil (WCS) and WTI varied significantly from a high of over $25 (US $) per barrel in 2018 to a low of under $10 (US $) per barrel in 2020. The periods with higher differentials (2005–2008, 2011–2014, and 2018) occurred during periods in which pipeline capacity was constrained, but the trend line over the period of increasing exports to the US is downward and there is a negative correlation between increased Canadian exports to the US and the price differential. These price trends show that the oil market is a complex interaction of many variables but MS's conclusion that increased exports to the US will have a clear and predictable downward impact on Canadian oil prices and that TMEP will therefore increase returns for all Canadian oil producers by reducing shipments to the US is incorrect. The key variable determining the differential is availability of adequate transportation capacity, not dependence on the US market.

Appendix 3: Assessing the Impact of the New Federal Climate Plan on the Canadian Oil Production Forecasts

On December 11, 2020 the federal government announced an updated climate plan to help Canada achieve its environmental goals in conjunction with its economic goals (Canada, 2020). The plan, titled *A Healthy Environment and Healthy Economy*, builds on the 2016 Pan-Canadian Framework on Clean Growth and Climate Change and outlines actions that will allow Canada to achieve net-zero emissions by 2050 (Canada, 2020). The key focus areas and proposed actions of the 2020 climate plan are as follows:

Pollution Pricing (Carbon Tax)

- increase the carbon tax by $15/tonne a year starting in 2023, rising to $170/tonne of carbon pollution in 2030;
- ensure that the federal carbon price remains revenue neutral and returns tax revenues to households through direct payments;
- narrow the scope of the clean fuel standard to cover only liquid fuels used primarily in the transportation sector; and
- continue to maintain industrial competitiveness and manage carbon leakage by exploring border carbon adjustments with international partners.

Clean Energy Investment

- expand on the zero emission vehicle (ZEV) mandate and invest $287 million over two years through ZEV purchase rebates and $150M over three years in charging infrastructure;
- invest in electric public transit ($1.5 billion has been earmarked for zero emission buses);

- support energy transformations in heavy duty vehicles, rail, marine, and aviation;
- invest $964 million over four years to advance renewable energy and electrical grid modernization;
- invest $300 million over five years to provide clean electricity to rural, remote Indigenous communities; and
- make Canada a leader in clean power through investment in electrical grids, intertie projects, and small modular reactors and development of tax incentives, performance standards, and battery material supply chains.

Energy Efficiency Investment

- invest $2.6 billion over seven years in grants for home retrofits/energy efficiency improvements;
- invest $1.5 billion over three years for green and inclusive municipal/community building improvements with at least 10% of this funding for Indigenous communities;
- make capital available for energy efficiency retrofits in commercial and large-scale buildings;
- invest in Canada's green building manufacturing sector and supply chains; and
- facilitate long term infrastructure planning towards a net-zero emissions future.

Building Comparative Advantage in Clean Industry

- explore options to help small and medium businesses build green, resilient communities through tax cuts, targeted investments, and other means;
- decarbonize heavy industry through targeted investments, technology adoption incentives, and research & development programs that promote emission reductions, industrial resilience, and job creation;
- accelerate methane emission reductions in the oil and gas sector through a $750 million methane emissions fund and establish new methane emission targets for 2030 and 2035 based on best practices;
- phase out all fossil fuel subsidies by 2025;
- invest $1.5 billion in a low carbon and zero emission fuel fund to increase the production and use of new fuels;
- introduce Canada's hydrogen strategy for coordination and investment across the industrial value chain;
- build the "Made in Canada" brand to be associated with the cleanest and most sought after products and technologies in the world;
- invest $166 million over seven years to support clean technology in agriculture and set a national target for emissions reduction from fertilizers of 30% below 2020 levels;

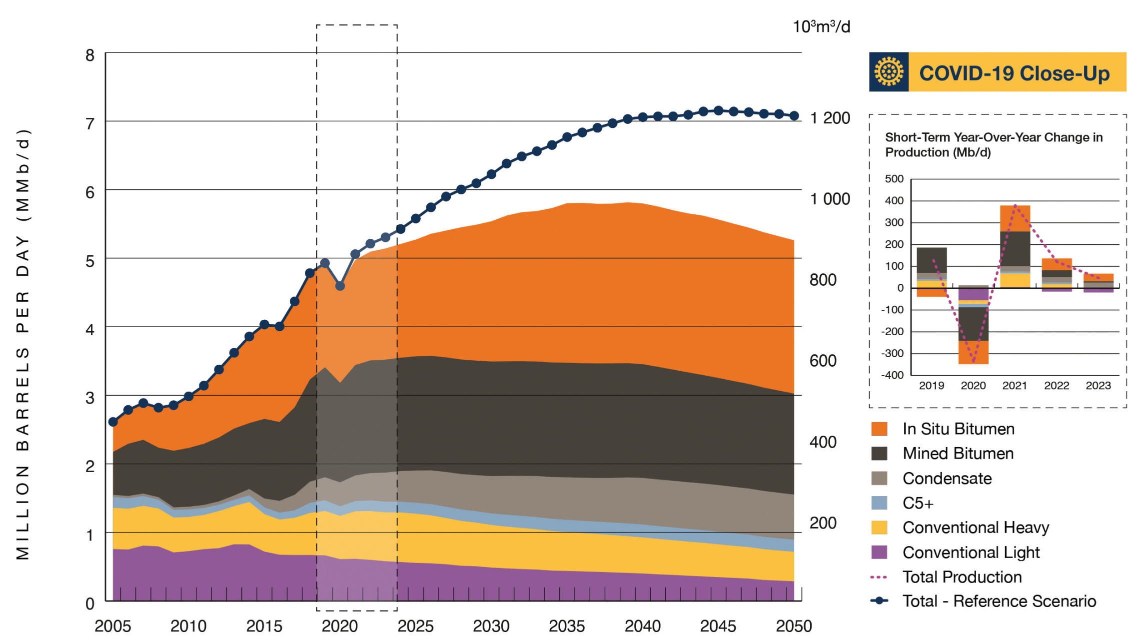
- take action to eliminate plastic pollution and develop new regulations for emissions regulation in landfills;
- invest in clean technology research, entrepreneurship, skills development, and career development; and
- mobilize sustainable finance through the issuance of federal green bonds in 2021–2022.

Natural Capital Investment & Protection

- invest $3.2 billion over ten years to plant two billion trees across Canada;
- invest $631 million over ten years to restore wetlands, peatlands, grasslands to boost carbon sequestration;
- provide $98 million over ten years to establish a Natural Climate Solutions for Agriculture Fund; and
- deliver on a commitment to protect 25% of Canada's land and 25% of Canada's oceans by 2025 and 30% of each by 2030.

This plan works in conjunction with the proposed *Canadian Net-Zero Emissions Accountability Act* (Bill C-12, 2020) which formalizes Canada's target to achieve net-zero emissions by 2050, establishes interim targets at five year periods, and holds current and future governments accountable to the targets. The proposed actions outlined in this climate plan are projected to cut emissions by 32%–40% below 2005 levels in 2030 without compromising GDP growth (Canada, 2020.

Figure A3.1 **Canadian Oil Production under the CER's Evolving and Reference Scenarios**



Source: CER, 2020b

The implications of this climate plan on Canada's oil and gas sector will be substantial. On November 25, 2020 the Canada Energy Regulator (CER) published its annual *Canada's Energy Future* report, which outlines two scenarios for future oil and gas production (Figure A3.1):

1. an "Evolving Scenario" forecast, which assumes that future climate policy will continue to strengthen at a historical rate of policy introduction; and
2. a "Reference Scenario" forecast, which assumes that no new climate policies will be introduced in future years.

The new federal climate plan invalidates the assumption underlying the CER Reference Scenario of no new climate policies and almost certainly eliminates the possibility that the CER's Reference Scenario forecast will be accurate. The CER's Evolving Scenario that assumes continued strengthening of climate policies is therefore a more likely forecast of future oil and gas production.

The Evolving Scenario is characterized by an assumption that actions to reduce the GHG intensity in Canada's energy system continue to increase at a pace similar to recent trends in Canada and around the globe (CER, 2020b). Specifically, the CER's Evolving Scenario makes assumptions about future domestic climate policies that include:

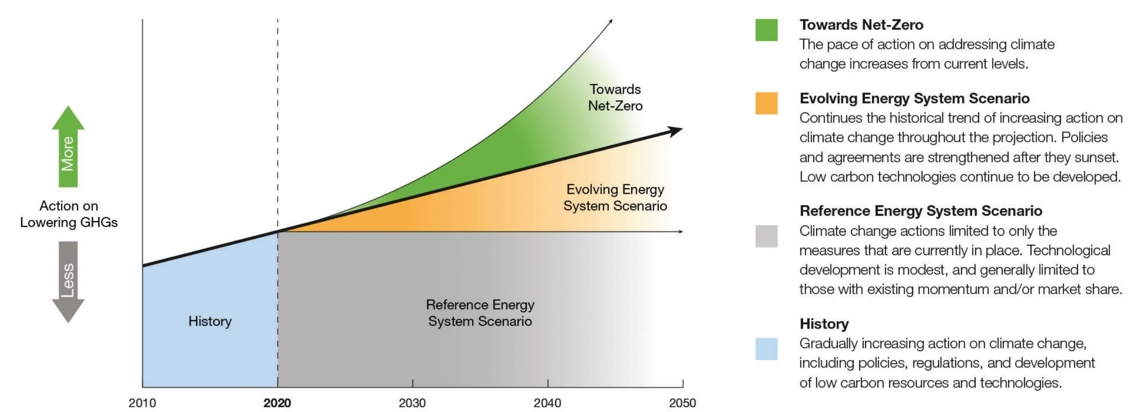
- a rising carbon tax of $125/tonne by 2050;
- gradually stronger energy efficiency regulations across all economic sectors;
- a low carbon fuel standard which gradually reduces the emission intensities of fuels;
- gradually increasing ZEV sales achieved through expanded ZEV mandates; and
- policy and technology development as for clean energy technology and infrastructure.

The Evolving Scenario also makes assumptions about future technological changes that include:

- utility scale battery storage capabilities by 2050;
- increased electric vehicle usage coupled with building electrification;
- electric freight trucking (3% of trucking needs by 2040 and 14% by 2050);
- gradually increasing small modular reactor usage; and
- carbon capture and storage usage (incremental 15MT/year by 2040, 30MT/year by 2050); and
- solvent assisted oil sands extraction for new projects and expansions post 2025.

This mix of assumptions, coupled with global climate policy development and clean technology uptake, leads to weaker fossil fuel demand and lower international prices for fossil fuel products. However, the CER Evolving Scenario may still overestimate future production because it assumes a slower rate of adoption of new climate policies than announced in the federal climate plan. The key difference between the CER Evolving Scenario and the federal climate plan is that the federal plan is intended to meet Canada's 2030 GHG emissions targets and the 2050 net-zero

Figure A3.2 Illustration of Climate Policy Introduction Rates under the CER's Reference, Evolving, and Towards Net-Zero Scenarios



Source: CER, 2020b

emission targets, while the measures in the CER Evolving Scenario fall short of meeting these targets (Figure A3. 2). This difference is evident when comparing the climate change policies in the federal climate plan with the Evolving Scenario (Table A3. 1). For example, the CER's pollution price assumption is $125/tonne of carbon in 2050 whereas the federal climate plan sets the price at $170/tonne by 2030 (Canada, 2020; CER, 2020b). The implementation of the carbon tax at this level (coupled with other climate policies to achieve net-zero emissions by 2050) means that climate action is already taking place at a rate that exceeds the recent historical average. Therefore, the CER's Evolving Scenario likely understates the changes that will occur in Canada's energy system and in the oil and gas sector in particular.

The CER does note that their Evolving Scenario will not allow Canada to achieve net-zero emissions in 2050 but they do not provide a comprehensive forecast which shows what the energy system would look like under net-zero policies (CER, 2020b). They do, however, include a discussion of the implications of net zero policies on the energy system. In particular, the CER notes that if the global energy system moves toward net-zero emissions global crude oil use is likely to decrease compared to current levels, prices will remain low, and technologies required to reduce emissions in the oil sands will keep costs high (CER, 2020b). Furthermore, broader environmental and social governance considerations could have an increasing role in oil sands investment decisions. The CER concludes that it is difficult to predict how companies operating in the oil sands will remain competitive in a global environment with lower oil prices, higher production costs, and increasing demands for emissions reductions (CER, 2020b).

In summary, with the new federal climate plan, the CER's Reference Scenario is no longer valid and CER's Evolving Scenario likely overestimates future oil and gas production. If the policies to achieve deep decarbonization and net-zero emissions are achieved domestically, oil producers will be challenged to operate in an environment where production costs are high. These challenges will be even more pronounced if further climate policies are implemented globally, thus reducing global demand and prices for crude oil products.

Table A3.1 Comparison of Climate Change Policies outlined in the CER Reference and Evolving Scenarios and the Federal Climate Plan

	CER Reference Scenario (Current Policies)	CER Evolving Scenario (Current + Future Policies)	2020 Federal Climate Plan
Vehicle Emissions Standards	• Light duty and heavy duty vehicle emissions standards with increasing stringency to 2027	• Same as Reference Scenario	• Increasing stringency of emissions regulations for light duty and heavy duty vehicles
Carbon Pricing	• Federal carbon backstop prices rising to and remaining at $50 in 2022 • Specific provincial programs for large emitters (energy intensive trade exposed)	• Carbon prices continue to rise beyond 2022, reaching $60 in 2030, $75 in 2040, and $125 in 2050 • Carbon pricing remains revenue neutral • Large emitters (energy intensive trade exposed) pay 50% of carbon costs in 2040 and 75% in 2050	• **Carbon prices rise $15 a year beyond 2022, reaching $170 in 2030** • Large emitters are covered under an output-based pricing system with a 2% tightening stringency every year post 2022 • Output-based standards for electricity generation decline after 2025, consistent with the goal of reaching net zero emissions in 2050
Low Carbon / Clean Fuel Standard	• Federal regulation for 5% ethanol blending in gasoline and 2% biodiesel in diesel • Provincial fuel emissions intensity regulations	• The clean fuel standard continues to reduce the lifecycle emissions of fuels beyond 2030 • Liquid fossil fuel emissions intensity is reduced by 10% in 2030, 20% in 2040, and 30% in 2050 • Gaseous fuel emission intensity is reduced by 2.5% in 2030, 6% in 2040, and 10% in 2050 • Coal use is phased out of power generation and reduced in industrial applications	• The clean fuel standard is narrowed to only include liquid fuels which are used primarily in the transportation sector. Carbon intensity of fuels drops by 13% by 2030
Canada-US Action to Reduce Oil & Gas Methane Emissions	• Methane emission reductions of 40%–45% below 2012 levels by 2025 for oil and gas extraction, processing, processing, and transportation facilities	• *Same as Reference Scenario*	• Strengthened methane regulations in the oil and gas sector and new methane capture regulations for solid waste facilities
Phase-out of Coal Fired Power Generation	• Phase out of all traditional coal fired electricity generation units by 2030	• *Same as Reference Scenario*	

Energy Efficiency Regulations	• Regulations to reduce emissions in government buildings • Other federal and provincial energy efficiency regulations	• Increasing regulations in residential, commercial, and industrial product categories • Fuel economy in light duty vehicles improves at 1% per year • Net zero building codes are adopted	• Net zero building codes ready for adoption by 2030 • Improving heavy duty vehicle efficiency standards aligned with the most stringent standards in North America
ZEV Standards	• Federal subsidies for electric vehicles in addition to provincial ZEV standards	• National ZEV sales reach 5% in 2030, 25% in 2040, and 50% in 2050	• Incentives for the acquisition and use of ZEVs to meet Canada's passenger ZEV adoption targets: 10% by 2025, 30% by 2030, and 100% by 2040 • 5,000 zero emission busses for public transportation fleets
Clean Energy Tech & Infrastructure Support	• Support for EV charging infrastructure • Support for renewable electricity generation • Reduction in diesel use for electricity and heat in northern communities	• EV charging infra-structure is deployed to accommodate rising ZEV usage • Electricity transmission infrastructure is increased • Carbon capture and storage technology use is increased • Technologies with limited current commercial applications are developed and deployed across the economy (e.g., hydrogen fuel cells, utility scale batteries, industrial electrification)	• Investments in a full suite of measures to enhance electrification in Canada (interties, grids, renewables, storage, small modular reactors) • Investments in clean energy in rural, remote, and Indigenous communities • Net-Zero Challenges for Large Industrial Emitters • Nature based solutions for emissions reductions

Sources: CER, 2020b; Canada, 2020

Appendix 4: Data Inputs for the Supply and Demand Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Supply of Transportation Capacity*																	
Existing Capacity	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931	3931
Rail	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Enbridge Line 3			352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
Enbridge Mainline Expansion	95	143	143	333	333	333	333	333	333	333	333	333	333	333	333	333	333
Express Expansion		48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Southern Lights Reversal				143	143	143	143	143	143	143	143	143	143	143	143	143	143
Keystone Expansion			48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Rangeland Expansion			76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
TMEP					561	561	561	561	561	561	561	561	561	561	561	561	561
Keystone XL					789	789	789	789	789	789	789	789	789	789	789	789	789
Total	4192	4287	4762	5095	6444	6444	6444	6444	6444	6444	6444	6444	6444	6444	6444	6444	6444
Total (ex. Keystone XL)	4192	4287	4762	5095	5655	5655	5655	5655	5655	5655	5655	5655	5655	5655	5655	5655	5655
Demand for Transportation Capacity																	
CER Evolving Scenario Oil Supply Forecast	4185	3651	4043	4314	4367	4421	4492	4531	4603	4661	4709	4745	4784	4788	4867	4926	4930
CER Reference Scenario Oil Supply Forecast	4185	3642	4143	4408	4513	4631	4777	4909	5077	5193	5292	5374	5462	5501	5638	5738	5768
Excess Transportation Capacity (CER Evolving)	8	637	719	781	2077	2023	1951	1913	1841	1783	1734	1699	1660	1655	1577	1518	1514
Excess Transportation Capacity (CER Evolving ex. Keystone XL)	8	637	719	781	1289	1235	1163	1125	1052	995	946	910	872	867	789	729	726
Excess Transportation Capacity (CER Reference)	8	645	619	687	1931	1812	1667	1535	1367	1251	1152	1070	981	943	806	706	676
Excess Transportation Capacity (CER Reference ex. Keystone XL)	8	645	619	687	1143	1024	878	746	579	463	363	282	193	154	17	-83	-113

Notes: *Pipeline capacity is shown at 95% of nameplate capacity

Appendix 5: Assumptions in the Financial Impact Analysis of TMEP

The financial impact assessment in this report uses a similar methodology as the PBO (2019) study. Both analyses rely on the TD financial information in the KM report (2018a) prepared for KM shareholders. Unfortunately, the TD financial assessment does not provide all of the assumptions and detailed financial information underlying their analysis. Consequently, there are number of questions as to the methodologies and underlying assumptions set out below that are material to the accuracy of results:

- The KM report (2018a) considers TMP as a stand-alone entity and models TMP cash flows independent of TMEP. This was done for one scenario in which TMEP does not proceed and two scenarios in which TMEP is built. The TD bank analysis in the KM report shows the cash flows associated with the existing pipeline (TMP) as the same in the scenarios where TMEP is built as in the scenario where TMEP is not built. However, the cash flows associated with TMP should be higher in the scenarios where TMEP is built because the tolls will be increased on TMP to the same level as on the TMEP for all oil shipments to cover the cost of the expansion project. It is likely that the TD Bank analysis accounts for this by including the incremental cash flows from higher tolls on TMP shipments in the cash flows of TMEP, but this is not explicitly stated.

- The KM report (2018a) includes two TMEP scenarios: one with capital costs of $8.4 billion and the other with capital costs of $9.3 billion. What is unclear is how the total capital costs associated with these scenarios translate into cash capital expenditures (capex) in the DCF. For example, in the $9.3 billion scenario, the KM report shows cash capex of $7.0 billion. The difference between the $9.3 billion and the $7.0 billion is not explained but is likely due to the exclusion of an unknown amount of capitalized interest along with $1.1 billion in TMEP spending before the project was sold to the Government of Canada (KM, 2018a). This discrepancy is important because it is unclear whether a 35% cost overrun (the difference between a $12.6 billion capital program and a $9.3 capital program) has a proportionally equivalent effect on cash capex. The PBO report has assumed that there is a proportional effect, but only considered capital cost sensitivities of +/-10%.

- Another consideration with respect to capital costs is what proportion of the capital cost overruns are passed on to shippers through increased tolls. Capital cost overruns associated with TMEP consist of a capped portion and an uncapped portion at an approximate split of 76% and 24%, respectively (CER, 2013a; KM, 2017, PBO, 2019). Tolling rates were set by the regulator based on a $7.4 billion capital cost (TM, 2017). If costs increase beyond the $7.4 billion, the uncapped portion of the capital cost overruns can be passed on to shippers through higher tolls, while the capped portion cannot be passed on without approval of the shippers (CER, 2013a). What is unclear in the KM report (2018a) is whether the cash flows are adjusted to cover all of the higher capital costs in their $8.4 billion and $9.3 billion scenarios or just the $7.4 billion capital cost plus the uncapped portion of the capital cost overruns. Our analysis[27] indicates that that the KM report likely uses tolls that cover a $7.4 billion capital cost program plus just the uncapped capital cost overruns. Thus, although the KM report does not explicitly state its assumptions, it appears that the uncapped portion (24%) of cost overruns is excluded from the cash capex figures, while the capped proportion of the overruns are included as a capital cost in the DCF analysis.
- The final capex spending schedule for TMEP remains unknown, but results posted by TMC (2020b) (the entity that currently owns and operates TMP and TMEP) indicate that the cash capex figures forecasted in the KM (2018a) report are inaccurate. TMC notes that $0.18 billion was spent on TMEP in 2018 following the sale to the Government of Canada, $1.25 billion was spent in 2019, and $3.0 billion will be spent in 2020. These figures are significantly lower than the amounts forecasted in the KM report for the same periods (2018a). The timing of the TMEP capital expenditures has a material impact on the total discounted cash flows, but it is unknown exactly what the final cost and spending schedule will be.
- The KM report (2018a) does not specifically identify the quantity of shipments and capacity utilization of the expanded system but states that cash flows are based on currently contracted capacity plus utilization of spot capacity. It is assumed that the utilization of the system is 95% (80% contract + 15% spot shipments), which is consistent with a previous capacity utilization analysis completed by Muse Stancil (MS, 2015), but

27 Analysis was completed by scaling both the $8.4 billion and $9.3 billion capital cost scenarios up to a $12.6 billion scenario by including only 76% of the cost overruns in the cash capex and comparing the final cash capex figures. Scaling the cash capex from the $8.4 billion scenario to the $12.6 billion scenario resulted in a cash capex figure of $8.902 billion. Scaling the cash capex from the $9.3 billion scenario to the $12.6 billion scenario resulted in cash capex of $8.910 billion. The difference between these figures is within a range where the difference can likely be explained by rounding errors. This analysis indicates that the KM report likely took the approach of only including the effect of the 76% of capped cost overruns in their analysis and considered the net effect of the uncapped cost overruns on cash flows to be $0.

this is not explicitly outlined in the KM report. This assumption is key for conducting sensitivity analysis on the effect of variable spot shipment volumes.

Base Case Assumptions

In light of these considerations, the financial evaluation in this report uses the following base case assumptions:

- cash flows associated with higher tolls on TMP are reflected in TMEP cash flow figures;
- the capital cost increase to $12.6 billion from the $9.3 billion scenario used in KM (2018a) report has a proportionally equivalent effect on cash capex;
- the $12.6 billion capital cost scenario is reflective of a $7.4 billion scenario where 76% of the cost overruns are capped and presented in the cash capex figures. The remaining 24% of cost overruns are uncapped and passed on to shippers through higher tolls but are not included in the cash capex figures because they have no effect on net cash flows;
- TMEP capital expenditures in 2020 are based on guidance provided by TMC. Capital expenditures in prior years (2018 & 2019) are the actual spending figures from those years. Capital expenditures in future years are based on the forecasted total capital expenditure less spending in 2018, 2019, and 2020. The future capital expenditures are evenly distributed between 2021 and 2022;
- the TMC pipeline system operates at 95% capacity (80% contract + 15% spot shipments);
- Changes in spot volumes have a non-linear effect on TMC cash flows in the contracted period because spot tolls are higher than contract tolls. The effect is linear in the fee-for-service period after expiry of the long-term contracts ;
- the inflation rate between 2018 and 2020 is 1.01% annually (Bank of Canada, 2020);
- a discount rate of 6% is used for TMP & 10% for TMEP (similar to the KM (2018a) and PBO (2019) analyses); and
- under the sale of TMC to a private entity scenario (see section 5.4.2), the sale is assumed to occur in 2024 (following one year of operating results) and a private entity will apply a 12% rate of return to value the future cash flows of TMP and TMEP.

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