State's Statement Regarding Draft of Alternatives Analysis

June 29, 2017

On August 24, 2016 the MDEQ, MDNR, MAE and AG's Office, collectively referred to as the State, entered into contract with Dynamic Risk Assessment Systems to conduct an Independent Alternatives Analysis of Enbridge's Line 5 Pipelines crossing the Straits of Mackinac. The Alternatives Analysis is one of two studies recommended in the Michigan Petroleum Pipeline Task Force Report released in July of 2015.

As explained in the Task Force Report and detailed in the Statement of Work included in the contract, the Alternatives Analysis is intended to be a systematic comparison of the feasibility, costs, benefits and risks of several alternatives, including, as a base case, continued operation of the existing Straits pipelines. An independent, detailed engineering evaluation of the existing pipelines and of their safe and reliable operating life was to be included. The contractor was not charged with recommending a preferred alternative. Instead, the overall purpose was to provide the State, Enbridge and the public with information that can be used to help guide decisions about the future of the pipelines.

Dynamic Risk released its draft Alternatives Analysis report to the State, as promised, on Thursday, June 22, 2017 at approximately 10:00 PM (EST). This was the first time the State had receipt or possession of any written results from the analysis.

Upon receipt of the draft report, the State project team, consisting of appointed staff from each of the respective departments, began an initial review. The goal of that initial review was solely to quickly assess whether the report included key elements required by the Statement of Work included in the contract.

On Friday, June 23, 2017, the State project team conducted two internal conference calls to discuss their initial review, which at that point was necessarily limited to only partial review because of the length and complexity of the draft report and supporting documents. The State project team then had two conference calls with Dynamic Risk seeking clarification about two points of the draft report and how, as written, they addressed key elements in the Statement of Work that was agreed to by Dynamic Risk:

The first point of clarification relates specifically to the following description of part of the Spill Cost Analysis on page 25 of the Statement of Work, which states:

> *"Spill costs will be estimated for up to three scenarios in each alternative. The three scenarios will be characterized as: (i) technical worst case spill to reflect an outflow and conditions associated with*

greatest volumes or environmental impacts; (ii) economic worst case spill to reflect an outflow of potentially lesser volume into a HCA[High Consequence Area] as defined in 3.1 above; and, (iii) a most credible worst case scenario."

The State project team indicated that the discussion of "worst case" spills in the draft report was unclear and suggested the need to explain and clarify how it had done so across the various alternatives, particularly with regard to Alternative 5, continued operation of the Straits Pipelines. The team noted that the parameters used to develop and identify the worst case spill scenarios and the corresponding estimated spill costs will be of special interest to both the State and the public.

<u>The second point of clarification</u> pertains to the engineering analysis of the existing Straits pipelines, which is described, in part, on page 3 of the Statement of Work, which states:

"This alternative will include a comprehensive engineering analysis of the current condition and operation of the existing Straits pipelines. The comprehensive engineering analysis of current conditions will include a review of the Enbridge integrity standards for the pipeline and protocols for detecting and responding to deviations from those standards. The analysis will also consider how long the existing pipelines can reasonably be operated without replacement as well as the course of action for replacement based on the estimated useful life of existing pipelines."

The State project team indicated to Dynamic Risk that the draft report did not appear to clearly address the estimated length of time the current pipelines can be operated without replacement. The team also noted that in discussing various potential threats to pipeline integrity, including spanning, the draft report did not address evidence of excessive span lengths prior to 2005 and whether they may have negatively affected the condition of the pipelines.

As a result of the conversations mentioned above, Dynamic Risk provided a revised draft of the Alternatives Analysis, including a new "Management Level Executive Summary." That revised draft immediately follows this statement. The revisions provided by Dynamic Risk reflect changes they chose to make to address the items mentioned above. Dynamic Risk also chose to take the opportunity to make other editorial revisions in areas not identified by the State, largely to remedy typographical and other minor errors.

The State has not mandated, approved or endorsed the content of either the initial draft or the revised draft of the Alternatives Analysis. Both documents are solely the work of the Dynamic Risk. The State reserves its ability to make additional comments regarding these topics and any other aspects of the draft Alternatives Analysis.

The State encourages the public to comment on the revised draft of the report, which immediately follows this statement, as it represents Dynamic Risk's latest work. In the interests of complete transparency to the public, the initial draft of Dynamic Risk's Alternatives Analysis, as well as a log of changes they made between the initial draft report and the revised draft report, are also available for those who are interested, by clicking the download button below.

The State intends to continue to review the report in detail to identify and compile additional areas for further consideration by Dynamic Risk. The State will post its comments publicly on the same website and on the same calendar as it is asking members of the public to do.

Draft Final Report

Alternatives Analysis for the Straits Pipeline

June 27, 2017

Prepared for

State of Michigan

Prepared by

Dynamic Risk Assessment Systems, Inc.

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Revision Log

Rev.	Date	Description of Revision
0	June 22, 2017	Draft Final Report
1	June 27, 2017	Revised based on comments and corrections

Reviewed and Approved By

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Management Level Executive Summary

The State of Michigan has retained Dynamic Risk Assessment Systems, Inc. to perform an independent analysis of alternatives to the existing Straits Pipeline. The results of this study will be relied upon by the State and other interested parties in making decisions about the future of the Straits Pipeline.

This Management Executive Summary is intended to provide a high level overview. It must be recognized that any use of statements herein should be supplemented with supporting facts and assumptions embodied in the Technical Report.

The Straits Pipeline, as referred to herein, was installed in 1953 and is comprised of two 20-in. diameter pipelines that lie on the lakebed at a maximum water depth of 250 ft., extending approximately 4.5 miles across the Straits of Mackinac. The Straits Pipeline is owned and operated by Enbridge Inc., and is part of their Line 5 system that transports approximately 540,000 barrels/day of crude oil and natural gas liquids (product) from Superior, Wisconsin to Sarnia, Ontario, Canada (645 mi.). The Straits Pipeline was constructed using heavy-walled pipe (0.812-in.), operates at a relatively low stress level, and the two 20-in. diameter pipelines are separated by about 1,300 ft.

Line 5 is an integral part of Enbridge's Lakehead system, which transports approximately 2,600,000 barrels/day to markets in the US Midwest, US East Coast, and Eastern Canada. Line 5 is the only component of the System with capacity to deliver 2,000 barrels/day of gas liquids for propane production to a facility in Rapid River, MI serving Michigan's Upper Peninsula. Line 5 also receives approximately 10,000 barrels/day of light crude oil from wells in Michigan's Lower Peninsula. Line 5 deliveries also supply Detroit and Toledo refineries, which are an important supplier of gasoline and other refined products to Michigan.

The analyses performed include assessments of ***design***-based cost estimates, ***economic*** feasibility, ***socioeconomic*** impact, ***market*** impacts, and ***operational risk*** including the consequences associated with an oil spill. The results of this analysis are described below and are grouped as follows:

- Analysis of the ***Existing*** Straits Crossing,
- Alternatives ***Remote*** to the Straits Crossing – new pipeline route and rail car,
- Alternatives in ***Proximity*** to the Straits Crossing – new trenched crossing and tunnel, and
- ***Abandonment*** of Line 5.

Each of these alternatives, along with an assessment of Line 5 abandonment, are described below.

Analysis of the Existing Straits Crossing

As a base case for comparison to alternatives to the Straits Crossing, an operational quantitative risk analysis, considering likelihood and consequences of failure, was completed for the existing Straits Crossing (Alternative 5). This base case forms the basis to which all other alternatives were compared.

The risk analyses conducted within this study and for each alternative are regarded as objective assessments of credible threats to existing or new infrastructure, and were based on an evaluation of threats, defined as the potential causes and failure mechanisms associated with spills. Three measures of risk were presented; Health and Safety Risk, Economic Risk, and Environmental Risk. These risk analyses are intended to provide a consistent means for comparing risks of alternatives.

For the existing Straits Crossing, the principal threats identified in order of decreasing contribution were anchor hooking, incorrect operations, vortex-induced vibration (VIV), and spanning stress. Anchor hooking, an inadvertent deployment of anchors from ships traveling through the Straits, represented more than 75% of the annualized failure probability ($3.6x10^{-4}$ rupture/year).

The consequences of a failure were also evaluated for the existing Straits Pipeline. The consequence analysis included 360 simulations that considers many factors (e.g., time of year, wind speed, location) to evaluate a distribution of single spill trajectories that could affect the shoreline. The pipeline failure modes evaluated included a full bore rupture (20-in. diameter opening) and a leak (3-in. diameter opening) that could produce a release volume of 2,600 barrels (10 minute detection) and 4,500 barrels (30 minute detection), respectively. The release volumes also consider additional time beyond detection for pump shutdown (30 seconds), valve closure (3 minutes) and drainage time ranging from 1.0 hr to 5.8 hrs. The monetized cost estimate for a release ranged from $100M to $200M, where approximately 60-percent of these costs represented environmental remediation. The spill modeling concluded that a single spill could on average impact about 20 miles of shoreline primarily affecting Cheboygan, Emmet, and/or Mackinac counties.

Alternatives Remote to the Straits Crossing

Some alternatives to the Straits Crossing were eliminated during the early stages of analysis. For example, there were limited options for using existing pipeline infrastructure (Alt 2) due to limited capacity on existing assets, whether they are owned by Enbridge or other parties. Even in cases under consideration, it was highly probable that either a new build pipeline or alternative transportation such as rail would be required to manage capacity. Therefore, the option of using existing pipeline infrastructure was removed from further detailed analyses.

The use of railroad transportation (Alt 3) was considered in detail within this study. Alternatives such as tanker trucks and oil tankers/barges were evaluated and eliminated from further consideration. For example, the volumes through Line 5 would require one tanker truck leaving the terminal every 40 seconds, 24 hours/day, requiring 3,200 tanker trucks/day. Tanker/barge transportation of the product would require passage through the locks on the St. Marys River at Sault Ste. Marie (the ‘Soo Locks’). In addition to significant capital investment required for barge tankers, recognizing that The Soo Locks are aging and in need of substantial investment for increased usage, and that the Soo Locks are down for repairs for 2-1/2 months each year, this alternative was eliminated as a viable alternative and includes consideration that it would require operational and capital costs in excess of $4.3 billion.

Three (3) alternative routes were considered for new pipeline construction (Alt 1) and the Southern Route was deemed most feasible. The Northern and Central Route were eliminated from further consideration due to construction challenges for a Northern Route (1,264 mi.) that includes Precambrian shield along 76% of the route and the inability to eliminate a crossing of the open waters of the Great Lakes for the Central Route (1,001 mi.). The Southern Route (Alt 3) that was evaluated would require the construction of 762 mi. of pipeline through Wisconsin, Illinois, Indiana, and Michigan (226 mi.). The Southern Route is advantageous in that it could follow existing pipelines for most of the route. However, the main drawback of this route is the congestion that may be encountered through the urban areas. In addition to the $2 billion in capital expenditure, this alternative would have an increased safety risk, monetized environmental risk and total economic risk when compared to the existing Straits Crossing (Alt 5).

The alternatives remote to the Straits Crossing present a failure frequency, safety risk, total economic risk, and monetized environment risk that is greater than any of the alternatives in proximity to the existing Strait Crossing. They also would not be available at the required scale for three to five years.

The economic feasibility of these remote alternatives is reflected in measures of stand-alone economic efficiency. The current cost of service using existing tariffs between the Superior and Sarnia area is approximately $1.50/barrel. The remote alternatives generate standalone cost of service delivery at costs (including Line 5 abandonment) in the range of $1.70/barrel to $6.50/barrel. Also, abandonment of Line 5 whether standalone or associated with one of these alternatives would adversely impact Michigan consumers. Market impact analyses concluded that propane users in the Upper Peninsula could face price increases in the range of 10¢/gallon to 25¢/gallon. Lower Peninsula producers would face an additional cost of $2.40/barrel to get their oil to market. Increased delivery costs of crude oil to Detroit and Toledo could push gasoline prices in Michigan up by about 2¢/gallon for stand-alone abandonment, and possibly by almost 4¢/gallon if rail became a dominant delivery source.

Alternatives in Proximity to the Straits Crossing

The alternatives evaluated in proximity to the existing Straits Crossing included the construction of a new trenched crossing (Alt 4a) and the construction of a new tunnel crossing (Alt 4b) that would be comprised of a single 30-in. diameter pipeline.

The construction of a new 30-in. diameter trenched crossing (Alt 4a) would require capital expenditures of approximately $30M, whereas the 30-in. diameter tunnel crossing (Alt 4b) would require approximately $150M. The operating costs for these options, along with the continued operation of the existing Straits Crossing (Alt 5) are the same. There would be a reduction in the operational risk for these alternatives where the environmental and economic risk relative to the existing Straits Crossing (Alt 5) would be 1/5th for the trenched crossing (Alt 4a) and would be negligible risk for the tunnel crossing (Alt 4b).

With respect to economic feasibility, the standalone incremental cost of these alternatives is less than $0.05/barrel and market impacts are negligible. There would be no discernible impacts to propane supply in the Upper Peninsula, or to crude producers in the Lower Peninsula. The Detroit and Toledo refineries would face no discernible increased supply costs or shortages requiring them to revert to higher cost options.

Economic impacts of all alternatives were also evaluated. Current Line 5 operations involve just over $80 million in annual expenditures in Michigan. These expenditures contribute about 900 permanent jobs throughout the Michigan economy, and generate some $45 million earnings and $7-10 million in taxes annually. This would not change materially if operations were to include a 30-in. diameter trench or tunnel crossing. By contrast, operations from the remote operations are expected to generate similar order of magnitude impacts within Michigan: 400 to 1500 jobs, $25 million to $85 million in earnings, and $6 million to $12 million in taxes.

All alternatives except the base case would be expected to generate construction impacts, which reflect the capital expenditures that might occur in Michigan and the availability of materials within Michigan (the state has no line pipe manufacturing). Construction impacts from a trench or tunnel crossing would generate 400 to 1,800 near-term jobs state-wide, respectively. The remote rail alternative generates no additional construction impacts in Michigan, because all new facilities are outside of the state. A new pipeline through southern Michigan would, however, consist of new pumping stations and construction spreads; these would potentially generate about 8,000 near-term jobs and almost $400 million in earnings.

Abandonment of Line 5

In order to fully abandon the Straits Crossing, the entire 30-in. diameter Line 5 (645 mi.) would be removed from service. The abandonment of Line 5 would cost about $200M and would also produce an increase of 10¢/gallon to 35¢/gallon for propane in the Michigan Upper Peninsula. The system would go into apportionment, causing supply squeeze and higher product costs in Detroit/Toledo (462,000 barrels/day refinery capacity and major suppliers to Michigan). The local prices for refined petroleum products would be expected to increase by 2¢/gallon for the 5.7 billion gallons of gas and refined petroleum product consumption each year in Michigan.

Full pipeline abandonment of the entire length of Line 5 is also a form of construction project, even though much of the abandonment would utilize safe methods for *in place* abandonment. Full abandonment is expected to generate approximately 2,000 near-term jobs for this activity.

Technical Executive Summary

Overview

This report has been submitted to the Michigan Department of Natural Resources (DNR), the Michigan Department of Environmental Quality (DEQ), the Michigan Agency for Energy (MAE), and the Michigan Office of Attorney General (AG) – collectively referred to in this report as the State of Michigan (the State) – as part of the State's Public Outreach Strategy. It addresses the scope of work as outlined in the State's *Request for Information and Proposals* on February 22, 2016:

> *to provide the State of Michigan and other interested parties with an independent, comprehensive analysis of alternatives to the existing Straits Pipelines, and the extent to which each alternative promotes the public health, safety and welfare and protects the public trust resources of the Great Lakes. The work does not include a recommendation by the contractor of a preferred alternative. Rather, the work includes the development of information that can be used by the State and other interested parties in making decisions about the future of the Straits Pipelines.*

The scope of work addressed within the analysis includes an independent review of the risks associated with Enbridge Pipelines' existing Line 5 20-in. pipeline crossings of the Straits of Mackinac as well as a technical evaluation of each of the alternatives contemplated by the State, as summarized below:

1. Alternative 1

   Construct one or more new pipelines that do not cross the open waters of the Great Lakes and then decommission the existing Straits pipelines.

2. Alternative 2

   Utilize existing alternative pipeline infrastructure that does not cross the open waters of the Great Lakes and then decommission the existing Straits pipelines.

3. Alternative 3

   Use alternative transportation methods (e.g., rail, tanker trucks, oil tankers and barges) and then decommission the existing Straits pipelines.

4. Alternative 4

   Replace the existing Straits pipelines using the best available design and technology. This Alternative considered two separate Straits pipeline crossing designs:

   a. Alternative 4.a. – Conventional trenched installation

   b. Alternative 4.b. – Tunnel installation

5. Alternative 5

   Maintain the existing Straits pipelines. As part of the analysis associated with this Alternative, the results of the threat and risk modeling were leveraged to provide an evaluation of the safe and reliable operating life of the existing Straits crossing pipelines.

6. Alternative 6

   Eliminate the transportation of all petroleum products and natural gas liquids (NGLs) through the Straits of Mackinac segment of Enbridge's Line 5 and then decommission that segment. This alternative would also reflect potential viability of continued NGL deliveries to the Upper Peninsula at Rapid River, and the continued receipt of Michigan light oil production at Lewiston.

Analysis Approach

The analysis considered Alternative 5 (maintain the existing Straits Crossing pipelines) as a baseline against which all other alternatives could be evaluated.

The analysis of each of the above alternatives includes the following elements (as applicable):

- Design-based cost estimates
- Economic feasibility analyses
- Socioeconomic impacts
  - Jobs, income and government revenue
  - Qualitative social impacts
- Market impacts
- Spill risk analysis:
  - Oil Spill Release Modeling
  - Oil spill behavior and impact modeling
  - Spill probability analysis
  - Spill consequence analysis
    - Spill cost analysis
    - Spill fatality analysis
    - Spill environmental consequence analysis

A high-level overview of the approaches taken for each of the above aspects of the analysis is provided below.

<u>Design-Based Cost Estimates</u>

For alternatives involving new infrastructure, cost estimates were based on prior experience in developing project cost estimates and designs for oil pipeline industry projects and operations, taking into consideration materials, construction, and construction support activities for the proposed infrastructure. Operational costs were also estimated by the project team, and were validated through inspection of public filings to regulators.

Design costs were established for the purposes of comparing the various alternatives using a common methodology. The costs generally reflect Class 5 estimates, representing an accuracy range of -30%/+50%. Costs estimated for this study exclude some owner costs (i.e., land costs) and do not reflect optimization that may occur at more advanced stages of design.

Final design costs were not generated for configurations that were determined to be infeasible (these include trucks, a new central pipeline route and a new central rail route). Preliminary cost estimates were derived for some designs that were not pursued further because of high cost, other logistical constraints, or both. Detailed cost estimates were prepared for the existing routing (two new crossing methods), decommissioning (existing Line 5 – terrestrial pipeline, facilities, and strait crossing pipelines), and southern rail and pipe alternatives.

Economic Feasibility Analysis

Economic feasibility analysis results are the first of three quantitative measures used to assess the various alternatives. Economic feasibility is regarded as an *efficiency* measure in economic terms. In standard economic analyses, it assesses the economic viability of a facility in terms of cost and benefit streams from normal operations: this is traditionally called a social cost benefit analysis. For this study, the alternatives described are designed to provide equivalent capacity and deliveries to that of the existing Line 5. In practical terms, this corresponds to total delivery capacity of 540,000 barrels/day (bbl/d), of which 1/6th is assumed to be NGLs. The project therefore employs a cost-effectiveness analysis to permit a simpler comparison that does not rely on explicitly estimating the benefit streams or revenues from the alternatives. Such a cost-effectiveness analysis is consistent with *OMB Circular No. A-4* (2003), which focuses on regulatory analysis of alternatives. It also serves as an appropriate comparative basis for performing subsequent market impact analyses.

The cost effectiveness analysis was undertaken for each alternative passing the preliminary screening. It was based on the present value of a cash flow profile of capital and operating costs needed to deliver a volume equivalent to that of the current pipeline infrastructure. This volume was selected as a benchmark to permit comparisons of alternatives independent of selected upstream and downstream impacts (which will be addressed elsewhere). The key reported metric was a levelized cost in dollars per barrel ($/bbl) terms. The levelized costs were subsequently used in market analyses to determine the degree to which producers, refiners, major industrial customers, and other consumers of energy products, may be impacted. A levelized cost can be thought of as the real (excluding inflation) price that must be received for every barrel of throughput over the life of a project for a transportation service to break even. The current Lakehead System toll to transport products from Superior to the Sarnia area is a useful benchmark for comparison: approximately $ 1.50/bbl.

For a standalone comparison of alternatives, the levelized costs were calculated based on the design-based cost estimates for each alternative, the throughput of the reference case for Line 5, which is 540,000 bbl/d, and a real discount rate of 6% per year.

Socioeconomic Impact Analysis

Jobs, Income and Government Revenue

Economic impact analysis results are the second set of three quantitative measures used to assess the six alternatives. These results are routinely provided in regulatory settings because they provide information about jobs, incomes, economic output – such as value-added and government revenue. Such results are impact measures in economic terms and provide complementary information to stakeholders and decision-makers relating to the economic desirability of a project. Hence, impact results are frequently presented alongside economic efficiency measures.

Economic impact measures are generally described in relation to a specific geographical area. This is the case with the alternatives considered in this study. Each assessed alternative was considered over three geographic areas:

1. A *county corridor* of the Michigan counties through which a given alternative passes (the smallest area).
2. A *Prosperity Region corridor* of the Michigan Prosperity Regions through which a given alternative passes (an intermediate area).
3. The State of Michigan (largest area).

Alternatives falling partially or entirely outside of Michigan were assessed based on the operating or capital cost impacts of that portion of the facility falling inside Michigan.

The input-output methodology on which this study relies involves the use of US Bureau of Economic Analysis (USBEA) statistics reflected in the second generation of its Regional Input-Output Modeling System (RIMS II). The project regards the models that are based on RIMS II multipliers to be an appropriate method for comparing the alternatives because they:

- generate internal consistency within the range of alternatives analyzed
- permit comparison of the multipliers, and results generated by this study and other studies within the State.

Although the study presents direct, indirect and induced impacts, the project regards the most robust of these estimates to be the direct and indirect impacts associated with the various alternatives. The project regards the induced impacts to be most robust for operating expenditures. Induced impacts associated with capital expenditures are less certain, but are appropriate for comparing across alternatives or to those from other studies.

The final category of economic impacts is that associated with government revenue impacts. RIMS II does not generate such results and does not estimate the induced or similar impacts of such revenues. The study estimates are based on independent assumptions across a series of State tax and revenue sources.

Qualitative Social Impacts

Socioeconomic impacts generally include the quantifiable indicators described above, but also can consist of a wide range of unquantifiable impacts that may be of concern to local stakeholders.

A social impact assessment (SIA) generally requires definition of a project with reasonably high certainty of routing options around a given configuration. With such information in hand, the SIA can follow well-developed protocols in the context of a public participation process. Because this study did not involve primary data collection or public processes, the assessments conducted here are regarded as preliminary *screening* exercises. In the case of environmental impacts, which may have some associated social dimension, a Rapid Impact Assessment Matrix (RIAM) is a commonly used screening tool that allows the transparent recording of the values and judgments made. For social impact screening, the project developed a tool consistent with:

- the procedures developed by the US Army Corps of Engineers
- recommendations from the Interorganizational Committee on Guidelines and Principles for Social Impact Assessment

The Committee is a group of social scientists endorsed by the National Oceanic and Atmospheric Administration (NOAA) and tasked to aid public and private interests in their SIA obligations under the *National Environmental Policy Act* (NEPA) and their SIA obligations to public agencies.

Market Impact Analysis

Market impacts are considered when changes to the current system might generate changes in prices within the context of product prices seen in Michigan or elsewhere. These market impacts are not tied to the economic impacts described above; instead, they are more closely tied to changes in the cost of product transportation into a given market area. In some cases, the market area is small and is more readily evaluated. Such is the case with the impacts of curtailment in transportation services for NGLs to Rapid River and for Michigan crude production in the Lower Peninsula. In both cases, the study screened a number of different technical alternatives for providing these services. For example, the existing 30-in. Line 5 could be considered for continued transportation, although at a much lower throughput, but this would generate operational integrity issues associated with operating a large pipeline at very low flow rates. Other configurations were also considered.

The project made the analytical assumption that market forces would, in the near term of service interruption, rely on some combination of trucking and rail for transportation. Incremental costs of these services were translated into potential ¢/gallon impacts for propane consumers in Michigan and potential $/bbl impacts for crude oil producers in Michigan. While, in principle, these market impacts could be spread to other stakeholders (e.g., propane producers or product refiners), for the small volumes involved here – propane consumers and crude producers are *price-takers* as opposed to *price-makers*. The brunt of any changes in delivery or collection costs are thus most likely to be absorbed by these stakeholders. In this context, the calculated impacts on Michigan consumers and producers are regarded as the maximum impacts that would be incurred from such a service interruption. Future market forces may change the dynamics of investment in transportation services (delivering propane and light crude). However, an assessment of such changes would be speculative and, in any event, any potential alternatives still need to be competitive with known existing means of non-pipeline transport of these products.

The assessment of larger market impacts of changes in product delivery are more complicated. The project, again, assessed the maximum anticipated impact on Michigan interests. These interests include primarily consumers of refined petroleum products (RPPs) in Michigan, and those interests associated with the Detroit refinery. The project acknowledges that Michigan's consumers could be impacted by costs borne by other refiners in the US Midwest (notably refineries in the Toledo, Ohio area). While some of the Line 5 crude oil crosses the border to Canadian refiners, documented flows of RPPs returning to the US Midwest (which includes Michigan) show negligible imports from Canada.

The assessment of impacts for any given alternative consists of three separate and largely independent parts:

- impact of decommissioning decision
- impact of abandonment costs
- impact of new facility costs.

In the case of the new crossing methods (e.g., Alternative 4 considers a new trenched crossing or tunnel crossing), only the last of these impacts comes into consideration. This is because the full Line 5 is not decommissioned and only a relatively low level of abandonment costs are incurred for the existing Straits Crossing of the twin pipelines. But for all other alternatives, all of these impacts must be considered. As background, Line 5 is part of a broader system of product movement that is regulated as the Lakehead System, which is operated by Enbridge. In simple terms, a product contracted for transport between Superior and the Marysville or Sarnia area, for example, will be transported at a published tariff – the routing choice is up to the operator. Costs are ascribed, not to individual lines, but to the system as a whole (e.g.; system fixed costs such as insurance or corporate overheads are recovered through all system throughput). Market impacts consider the eventual costs on the entire system.

Operational Risk Analysis

Risk is defined as a measure of the probability that a hazardous event (in this case, a hazardous liquid spill) will occur and the severity of the adverse consequences of that event. This report documents three dimensions of risk including public safety, environmental risk and economic risk.

Risk may be expressed qualitatively, semi-quantitatively, or as has been done in this report: quantitatively. When quantifying risk associated with an installation or piece of infrastructure, it is conventional to represent public safety risk as the expected number of fatalities per year of operation. Similarly, economic risk can be expressed as expected damage costs (dollars) per year of operation. These fully-quantitative representations of risk are possible because both the measures of probability and consequence may be presented in quantitative terms using consistent units of measure.

Environmental risk, however, may be perceived differently by different individuals, depending on social background, heritage, the degree of reliance of the environment for livelihood, personal values, etc. Because of this, one person's perspective on the magnitude of a given environmental consequence may be vastly different from that of another. Therefore, no government agency or regulatory body has established or adopted quantitative measures that are intended to capture all aspects of environmental risk. Nevertheless, for the purposes of characterizing and comparing the environmental risk between the various alternatives considered in this report, the environmental component of economic consequence has been adopted to represent environmental consequence. This measure of environmental consequence is based on a monetization of the damages, which in principle encompass the following impacts, provided that these impacts can be directly associated with a spill event:

- restoration costs of the natural environment
- a broad range of environmental damages normally included within a natural resource damage assessment (NRDA), including air, water and soil impacts
- net income foregone in the sustainable harvest of a commercial resource
- net value foregone in the sustainable harvest of a subsistence resource, including fisheries.

The risk analyses associated with each alternative were based on an evaluation of threats, defined as the potential causes and failure mechanisms associated with spills. The risk analyses therefore included threat assessments, during which the design, materials, operational and environmental characteristics of each alternative were evaluated against threat attributes. The Threat Assessment provided an evaluation of potential susceptibility, and potential failure mechanisms involved. For those threats characterized as having the potential to contribute to overall failure probability at significant levels, the threat assessments also provided a basis for proceeding with quantitative estimates of failure probability.

A variety of techniques were employed to estimate failure probability. These techniques included reliability methods, which employ advanced statistical methods against mathematical models that evaluate resistance to failure, logical methods, such as event tree modeling, and evaluation of industry incident data. Failure probability modeling provided estimates of the probability of incurring spills of various magnitudes. These spill magnitudes were then used as the basis for evaluating health & safety, environmental, and economic consequences. For each alternative, risk was determined as the sum of the products of failure probability and associated consequences. Three measures of risk were presented; Health and Safety Risk, Economic Risk, and Environmental Risk.

Oil Spill Release Modeling

Oil outflow analysis was performed using Dynamic Risk Outflow software (Version 0.97.0.4465) to estimate the amount of oil that could potentially release in the environment following a pipeline failure in the Straits Crossing.

Release volume calculations were based on the following assumptions:

- Outflow from two hole sizes; 3-in (75 mm) diameter and full-bore rupture, representative of the failure mechanisms associated with the principal threats.
- Outflow from three release locations, representing a range of positions within the bathymetric profile.
- Detection, response and isolation times that are approximately 4 x longer than those that are specified by the performance standards of the leak detection and isolation equipment currently in place at the Straits Crossing segments.
- Full drain-down to the fullest extent possible, given the elevation profile and valve configuration associated with the Straits Crossing segments.

The outflow results do not take account of any response, intervention or any attenuation of release volumes.

For the purposes of the fate and consequence assessment for the existing Straits Crossing segments, outflow volumes that were calculated based on the above assumptions were used in conjunction with a full range (including worst-case) of operating and environmental conditions applicable to these segments.

Oil Spill Behavior and Impact Modeling

The behavior of oil spills was modeled using MIKE software powered by the DHI MIKE 21 hydrodynamic oil spill (OS) module of the MIKE Flow Model. For the purposes of the analysis, the OS module was upgraded using DHI's proprietary three-dimensional software MIKE 3 to increase resolution in the relevant areas.

The MIKE 21/3 OS model was used to predict the spreading, drift and weathering of spilled oil under varying environmental conditions. Oil in the model is represented as Lagrangian particles drifting (being advected) with the surrounding water body and exposed to weathering processes. The drift of the individual particles is determined by the combined effects of current, wind and bed drag. The variation of current speed over the water depth is emulated by application of a drift profile, being a combination of a simulated current profile or traditional assumed bed shear profile (logarithmic) and wind acceleration of particles directly exposed to the wind.

Weathering processes cause the oil properties of each particle to change over time and with the ambient environmental conditions. An oil spill simulation using MIKE 21/3 OS describes the spreading, drift and weathering of a single spill that occurs over a given period and for a number of days after the spill has stopped.

For this study, a simulation length of 30 days was chosen to allow the full development of the spill.

From statistical analysis of the simulation results, predicted spill trajectory maps were generated to depict the:

- Probability of a given area being exposed to spilled oil.
- Minimum time for the occurrence of spilled oil to reach a given area after the initial release of the oil.
- Maximum length of shoreline exposure and extent of exposure above a threshold.

Spill scenarios were conducted for each combination of release volume and location. The behavior of oil spills is dependent on the hydrodynamic conditions, waves and winds prevalent at the time of the spill as well as the properties of the spilled oil. Spreading and weathering of the spilled oil are dependent on the environmental conditions occurring at the time of the spill, and vary significantly over time. To accommodate this uncertainty, multiple oil spill simulations were carried out over a one year period, using temporal and spatial varying environmental conditions derived from publicly available datasets:

- Hourly wind hindcast data were obtained from the National Center for Environmental Prediction
- Digital Elevation Models of Lake Huron and Lake Michigan were obtained from NOAA's Bathymetry and Global Relief Datasets.

- Verified hourly water levels were obtained from NOAA stations 9075080 Mackinaw City, MI, 9075065 Alpena, MI, 9075099 De Tour Village, MI, 9087096 Port Inland and 9087023 Ludington, MI
- Point measurements of wave parameters and current speed and direction at different depths/levels above the bottom were collected from ADCP recording stations.
- Gridded ice concentration data at a spatial resolution of 1800m were obtained from the NOAA Great Lakes Environmental Research Laboratory

All data were post-processed into MIKEZero compatible format. The results of the oil spill model were then presented as probability maps of a spill occurring in water and the zone of exposure (ZOE). Each map is composed from 120 single spill trajectories over one full year. In other words, the results do not present a single possible spill scenario but a distribution of possible spill trajectories. For each simulation, the starting time was selected randomly to avoid any bias in the drift trajectories.

Summary of Significant Findings

- A summary of significant findings associated with each aspect of the study listed below are included in this section:
- Feasibility of Alternatives
- Safe and Reliable Operating Life
- Oil Spill Behavior and Impact
- NGL Release and Dispersion Analysis
- Quantitative Results

Feasibility of Alternatives

All alternatives with the exception of Alternative 2 (utilization of existing pipeline infrastructure to transport Line 5 products) were found to be feasible, although of the alternative transportation methods evaluated in Alternative 3, only rail was characterized as being feasible and fully developed within the analysis.

From the analysis performed on Alternative 2, it was determined that there are very limited options to utilize available capacity on existing assets whether they are owned by Enbridge or other parties. The limited information on volume forecasts for 3rd party pipelines and the limited number of non-Enbridge pipelines connecting Superior and Sarnia limited the available capacity to two relatively short sections:

1. Partial capacity on Enbridge Line 78 from Stockbridge, MI to Sarnia, ON, 106 mi. (171 km) in length
2. Potential conversion of TransCanada mainline from North Bay, ON to Barrie, ON, 155 mi. (250 km) in length

Both options would need to supplement either a new build pipeline or alternative transportation such as rail to accomplish transport of Line 5 products from Superior to Sarnia.

The most obvious realignment of pipe infrastructure to backfill for Line 5 would be to re-activate the Portland Oil Import Pipeline to Montreal and reverse Line 9 from Montreal to

Sarnia, and reverse Line 78 to Stockbridge terminal. Oil can be shipped from Superior to the Gulf Coast by existing pipelines, and then by marine shipments from the Gulf to Portland. Terminal capacities are presently in place for this at Portland and Montreal.

The relatively short length of the available sections, combined with the limited information on availability of the TransCanada line mean that this alternative is not significantly different enough from Alternative 1 (construction of a new pipeline) to develop as a standalone analysis.

With respect to Alternative 3, in addition to rail, which was fully developed for analysis purposes, the feasibility of two other transportation methods (tanker trucks and oil tankers/barges) were evaluated.

To handle the Line 5 volumes would require an average of one tanker truck leaving the terminal every 40 seconds, 24 hours per day. It was determined that approximately 3,200 trucks would be required to maintain the flow of product. It was determined that the costs associated with procuring, maintaining and operating this fleet, along with the costs associated with developing terminals large enough to accommodate the flow of traffic would make this alternative prohibitive. Furthermore, it was established that the public costs associated with the strain and congestion that the increase in traffic would put on public infrastructure, as well as the associated risk to the public was sufficient to discard this as a viable alternative transportation method.

Tanker transportation of crude oil and NGLs from Superior to Sarnia would have to pass through the locks on the St. Marys River at Sault Ste. Marie (the 'Soo Locks'). The Soo Locks are aging and in need of substantial investment to bring them back to reliable operation for this additional traffic. Should a problem arise or a restriction be placed on these locks the feasibility of this option is severely limited.

Additionally, the Soo Locks between Lake Superior and Lake Huron are closed for repairs from January 15th to March 25th, or two and a half months, each year. To accommodate this situation, volumes would need to be transported by another means or storage capacity would be required in the Superior and Sarnia areas to handle the large buffer volume required. It was determined that such storage would cost approximately $2 billion, which would be on top of the $2.3 billion to procure the vessel fleet. It was established that these costs are prohibitively expensive for this to be considered further as a viable alternative transportation method.

Safe and Reliable Operating Life

Without adequate inspection and maintenance programs, pipeline integrity can deteriorate over time by the action of time-dependent threats. In the Threat Assessment that was completed on the existing 20-in. Straits Crossing segments, twelve separate threat categories were considered. Each of the twelve threat categories can be characterized as either time-dependent or time-independent; the difference between the two being that the passage of time influences the likelihood of failure for time-dependent threats, whereas the likelihood of failure is not influenced by the passage of time for time-independent threats.

Of the twelve threat categories, only for the threat of vortex-induced vibration does annualized failure probability change with time, increasing (due to the accumulation of fatigue cycles over time) from $1.42\text{x}10^{-05}$ per year to $1.61\text{x}10^{-05}$ per year over the time span from 2018 to 2053. This increase in annualized failure probability of $0.19\text{x}10^{-05}$ represents an increase of only 0.4% in the combined (All Threat) annualized failure probability over this time frame. Therefore, time does not represent a significant factor in the failure probability estimates derived for the existing 20-in. Straits Crossing segments.

Metallurgical Considerations of Time Dependency

Apart from the action of time-dependent threats, time-temperature reactions are possible at sufficiently high temperatures, and can cause changes in steel properties under such circumstances. Numerous studies and experiments have been conducted to characterize the effect of time and temperature on steel material properties. Typically, these experiments have been conducted at high temperatures (well above the operating temperature range experienced by most transmission pipelines) in order to accelerate the process. A meta-analysis of these studies undertaken by Battelle Memorial Institute concluded that no significant degradation in the material properties of pipeline steels occurs as a result of the passage of time.

Corrosion Assessment

Although a great deal of focus has been directed to the potential degradation in pipeline integrity due to external corrosion, a thorough assessment of all available information shows that provided that Enbridge maintains its current integrity management practices, this particular threat does not contribute to the overall probability of failure at a magnitude that is significant – particularly in relation to the contribution made by other threats. The following represents a high-level summary of the basis for that conclusion:

Coating

The Straits Crossing segments are coated with coal tar enamel (CTE) coating, which, although considered a vintage coating system discontinued after the mid-1980s, has a very good performance history, displaying good adhesion, and forming a continuous, strong bond that is resistant to moisture absorption and deterioration over time. Significantly, unlike other coating systems, CTE does not shield cathodic protection currents. While there has been some public concern expressed over the reference to coating holidays and delaminations in Enbridge's *Biota Work Plan*, it was clarified that those references to coating damage were made necessary by the conditions of the *Consent Decree*, which required that Enbridge conduct special investigations at areas of potential coating damage. Enbridge further clarified that the only coating damage it has identified to date involves the CTE outer-wrap, which in some cases, has become separated from the underlying coating material, which is still in contact with the pipe surface. This assertion is supported by the Cathodic Protection Current Mapping (CPCM) inspection conducted in September, 2016. This tool is designed to measure current density continuously along the length of the pipeline, as well as the location and magnitude of current leaving or entering the pipeline, which would be expected to occur at significant coating holiday locations. The fact that this tool reported no current density anomalies supports the contention of an intact coating. Other findings of significance are that low levels of current density along the entire length of the pipelines indicate that the coating is in excellent condition on both the East and West Crossing segments. Finally, in the project team's experience, it is not unusual for the outer layer of CTE coatings to separate from the underlying corrosion coating, with no apparent compromise made to the corrosion protection performance of the coating.

Cathodic Protection

While the results of the 2016 CPCM inspection of the East and West Crossing segments indicated that the current demand was low, and that this is largely attributed to coating performance, this finding is significant from the perspective of the demands on the cathodic protection system. Specifically, because there are relatively low demands on the cathodic protection system, it should be readily capable of imparting protective currents along the length of the pipe segments. This is supported by a review of cathodic protection potential survey records dating back to 1989, which show no sub-criterion readings.

Corrosion Assessments

High-resolution magnetic flux leakage (MFL) in-line inspections of the East and West Straits Crossing pipelines has been completed every five years since 1998, with the most recent inspection being completed in 2013. A review of the inspection reports indicated that the only external metal loss features identified on both the East and West Straits Crossing segments were those associated with manufacturing anomalies for which no mechanism exists for growth. An analysis of the growth of matched external metal loss anomalies between the 2008 MFL and 2013 MFL inspections indicated that all variances in depth were found to be within the ±10% depth measurement error of the tool. Therefore considering tool error, there is no growth of wall loss features; this is consistent with these features being manufacturing anomalies, rather than active, growing corrosion features.

Operating Experience

The lack of vulnerability to failure by means of external corrosion on the Straits Crossing segments of Line 5 is consistent with operating experience for offshore pipeline segments, which dictates that apart from offshore platform risers, cases of significant external corrosion on offshore pipelines are extremely rare. This is owing to the homogeneity of the offshore environment, the predictability of coating and cathodic protection due to uniformly high conductivity of the environment, and the creation of any exposed metal with calcareous deposits, which acts to inhibit corrosion.

Spanning Assessment

The evaluation of threat attributes indicated that the Straits Crossing segments are potentially vulnerable to two separate failure mechanisms related to spanning:

i) fatigue caused by vortex-induced vibration (VIV) at span locations, resulting from near-lake-bottom water currents; and,

ii) over-strain caused by stresses due to unsupported span length (gravity and water current drag forces)

With respect to the threat of VIV, depending on pipeline design attributes and span lengths, even moderate currents can induce vortex shedding, at a rate determined by the velocity of water flowing around the pipe. Each time a vortex sheds, a force is generated, causing an oscillatory multi-mode vibration. Under some circumstances, this vortex-induced vibration can give rise to fatigue damage and failure of submarine pipeline spans. The threat of VIV was analyzed utilizing an amplitude response model in which input parameters of span length and upper-bound bottom-layer water currents along both the east and west Straits Crossing segments were represented as probability distributions. The span length distributions reflect observations that actual span lengths have exceeded (in some cases, by significant margins), the 75 ft. maximum stipulated in the Line 5 easement agreement. Using a total of 100,000,000 simulations in a Monte Carlo analysis, the probability that fatigue life would be exceeded for each of several future time periods was determined up to the year 2053.

As a separate analysis, a stress analysis was conducted that considered stresses arising from both gravity and drag forces in addition to those arising from operating pressure and temperature. As was done for the VIV analysis, input parameters of span length and upper-bound bottom-layer water currents along both the east and west Straits Crossing segments were represented as probability distributions. For the purposes of the spanning stress analysis, the probability of failure was defined as the fraction of simulations in which the maximum combined effective stress exceeded yield stress. Using a total of 100,000,000 simulations in a Monte Carlo analysis, the probability that the pipe's yield strength would be exceeded by the maximum combined effective stress would be exceeded was determined. Although there is ample strain capacity beyond yield (and therefore, failure does not occur when the maximum combined effective stress reaches yield stress), yielding was selected as a failure criterion because it defines the onset of plasticity, which in a dynamic environment could give rise to high amplitude fatigue.

The analysis determined that the annual probability of failure associated with spanning-related threats was time-dependent, rising from $1.42x10^{-05}$ (3.1% of total, all-threat annual failure probability) in the year 2018 to $1.65x10^{-05}$ (3.5% of total, all-threat annual failure probability) in the year 2053.

Oil Spill Behavior and Impact

For unique combinations of release magnitude and location, oil spill simulations were conducted for the existing 20-in. Straits Crossing (Alternative 5) and the 30-in. Straits Replacement (Alternative 4). For the purposes of the Executive Summary, an overview of the results of the analysis performed for the existing 20-in. Straits Crossing is provided.

For rupture scenarios in the existing 20-in Straits Crossing segments, the majority of the spill trajectories are predicted to impact the shore of the core zone within the counties Mackinac, Emmet and Cheboygan. Single spill trajectories can travel further depending on the environmental conditions existing at the time of the spill.

Oil spill extent maps were generated based on a threshold of 0.01 g/m^2. This threshold represents the practical limit of observing oil in the marine environment. From an environmental perspective, 0.01 g/m^2 is a very conservative threshold with little impact on the feathers of birds. For each spill scenario (spill magnitude and location), oil spill extent maps were generated based on analysis of all 120 spill trajectory simulations.

Figure ES-1, which is based on all rupture simulation events for the existing 20-in. Straits Crossing segments, shows the percentage of oil spill simulations that reach a geographic extent.

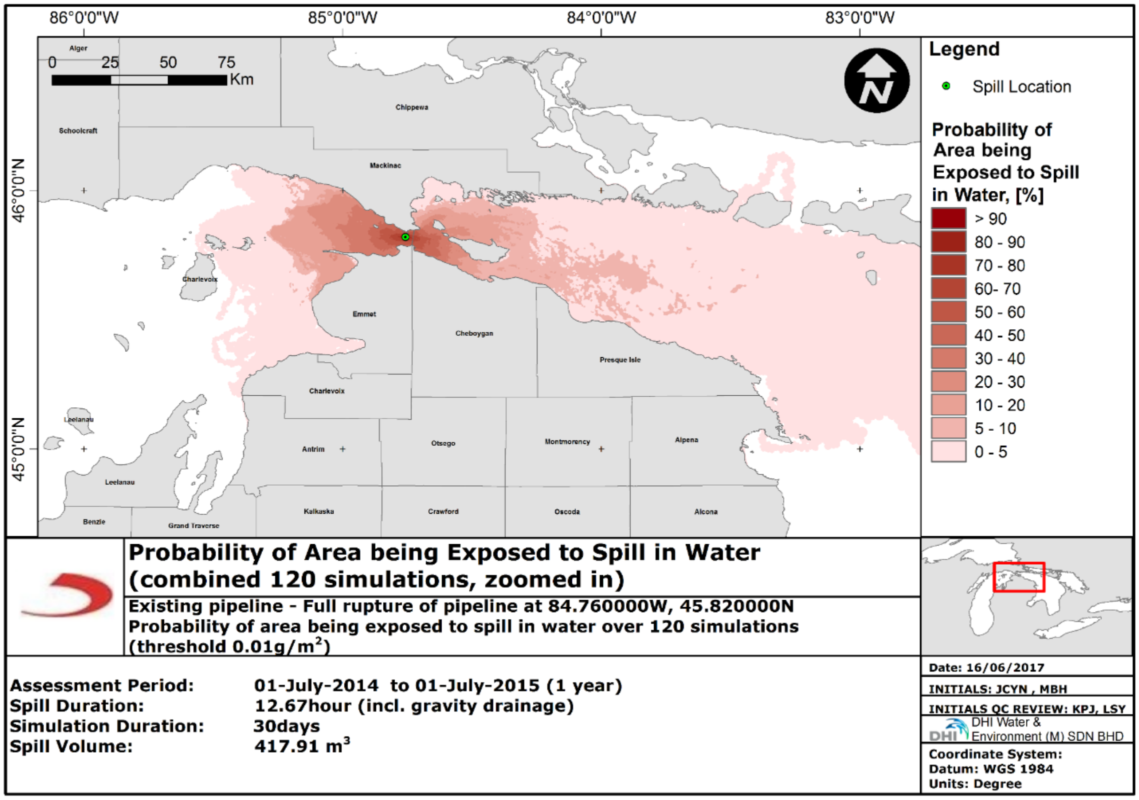

Figure ES-1: Existing Straits Crossing Probability of Area Exposed Rupture Scenario (Threshold 0.01 g/m2)

Besides the assessment of the full year, seasonal-specific patterns were analyzed by dividing the year into four quarters. Each quarter includes 30 simulations, randomly distributed by time of spill. From the analysis, it was apparent that during the winter season (Q3) the spill extent is the smallest. This is due to the ice cover preventing the spill from fully developing all the way to the shoreline.

Zone of Exposure (ZOE) maps were generated that represent the shoreline that is being exposed to the combined oil spill scenarios. The maps show the combined result over all 120 simulations with each point depicting the maximum value realized at the shoreline over all 120 simulations. The ZOE maps classify the exposure into three categories ranging from Low (barely visible sheen, although with fishing prohibitions and socioeconomic impacts) to High (harmful to all birds coming into contact with the slick). The ZOE map associated with a mid-channel rupture scenario for the existing 20-in Straits Crossing segments is depicted in Figure ES-2.

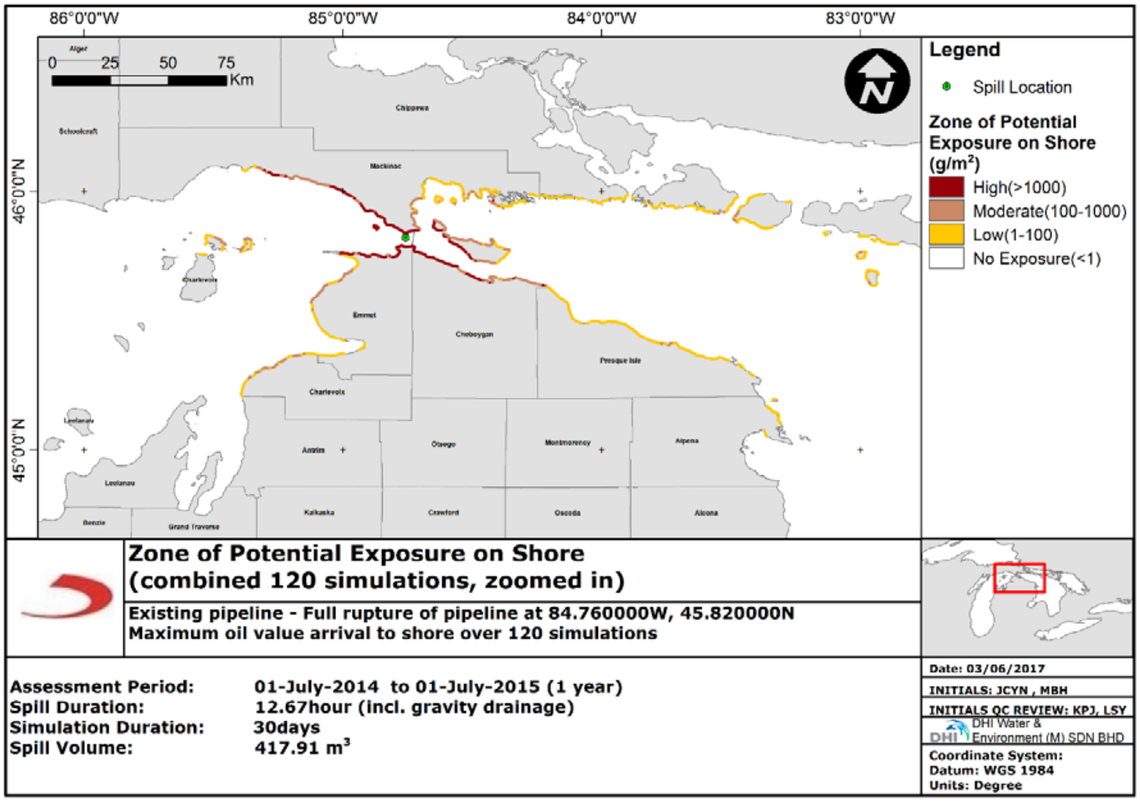

Figure ES-2: Existing Straits Crossing Zone of Potential Exposure on Shore Rupture Scenario (g/m^2)

The arrival time to shore depicted in Figure ES-3 predicts the time for the oil spill to reach the shoreline after the time of the spill. In that Figure, all simulations of mid-channel ruptures involving the existing 20-in. Straits Crossing segments are mapped together, meaning that the shortest arrival time to shore over all 120 simulations is shown. Longer arrival times to the shore allow for mitigation measures to be put in place to protect key receptors, compared to short arrival times where there may not be time to respond before the oil reaches shore.

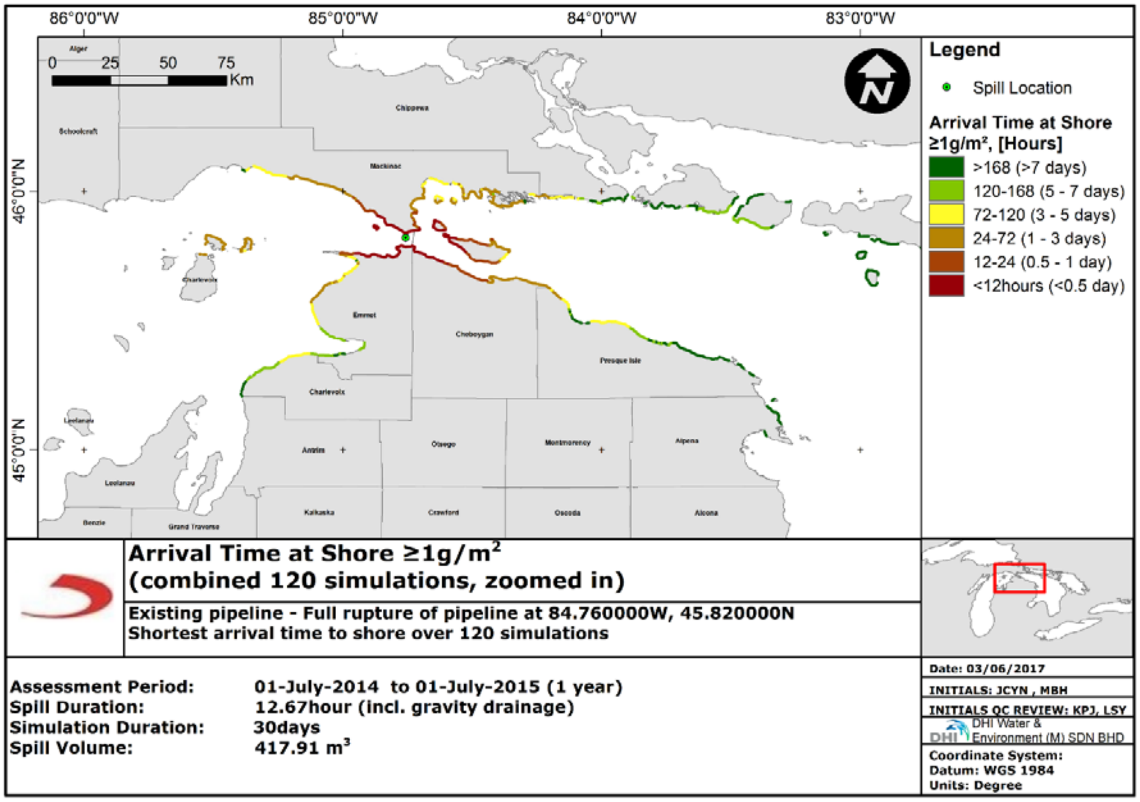

Figure ES-3: Existing Straits Crossing Arrival Time to Shore – Rupture

The scenarios for pipeline leakages at the northern and the southern shores were found to be similar to the rupture scenario in terms of distribution of the spill. However, due to larger volumes spilled in the southern shore scenario, the zone of potential exposure is predicted to receive higher concentrations at the shoreline for the southern shore spill scenario (see Figure ES-4 and Figure ES-5).

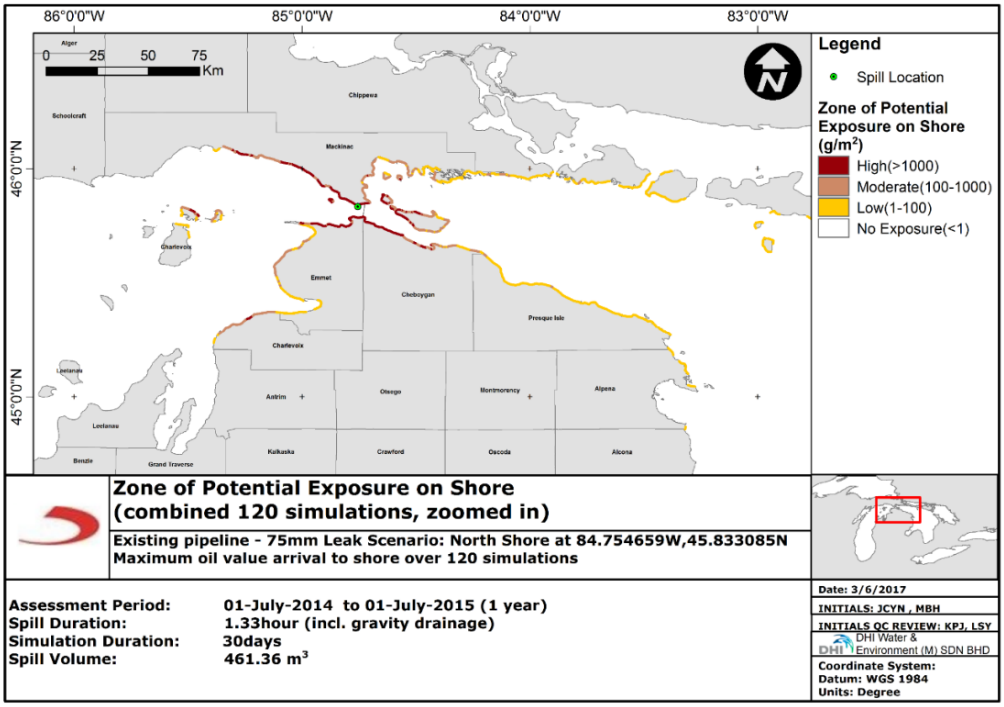

Figure ES-4: Existing Straits Crossing Zone of Potential Exposure on Shore For Near-North-Shore Leak Scenario (g/m^2)

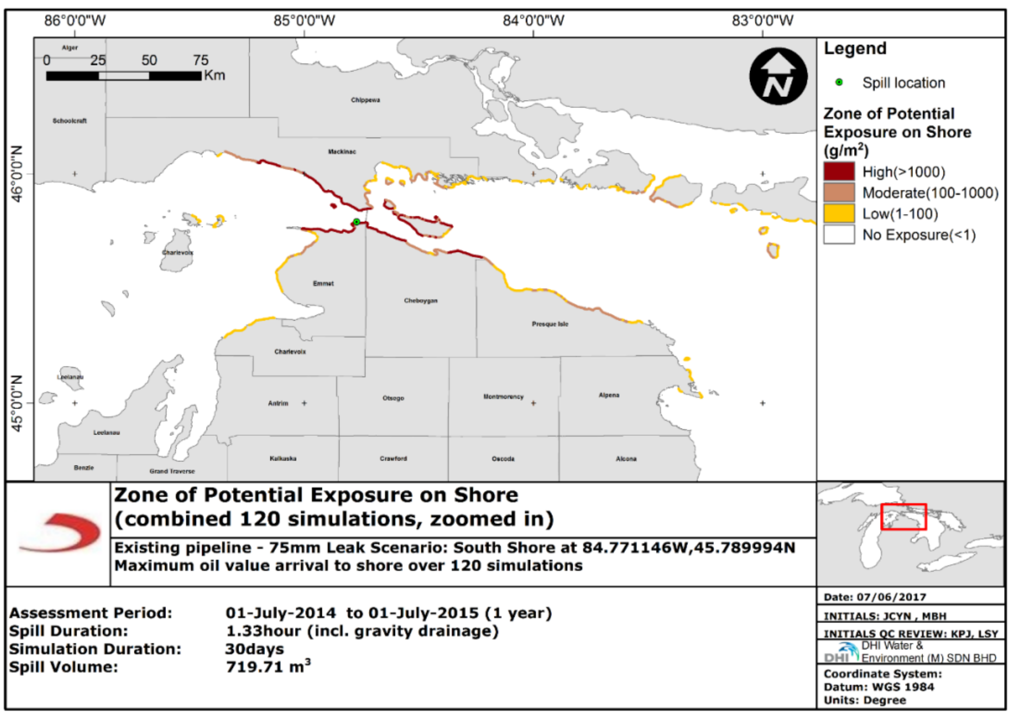

Figure ES-5: Existing Straits Crossing Zone of Potential Exposure on Shore For Near-South-Shore Leak Scenario (g/m^2)

NGL Release and Dispersion Analysis

A simulation of the NGL releases caused by a failure of the Straits pipelines was conducted using PipeTech software. PipeTech is a computational fluid dynamics (CFD) computer program that predicts transient fluid flow dynamics following the failure of pressurized pipelines. The program provides NGL discharge rates, which are subsequently used to predict the dispersion and travel behavior of gas plumes in and on the surface of the water.

Consistent with the oil release analysis performed for environmental consequence analysis, NGL release sizes were determined based on the Principal Threats identified in the Threat Assessment. In that respect, releases from full-bore ruptures and 3-in. (75 mm) holes were simulated.

To account for the variation in the water depth and investigate the impact of the release depth on the release rates, five scenarios of varying water depth and position were modeled. Release rates were then used to perform NGL dispersion analysis using the Unified Dispersion Model (UDM) within DNV PHAST v. 7.11, accounting for under-water release behavior, boil zone development, and atmospheric conditions. Flame envelope sizes (used for the purposes of the Health and Safety Risk Analysis) were then determined to be 4,729 ft. (1,441 m) for rupture scenarios and 1,526 ft. (465 m) for leak scenarios.

Quantitative Results

Quantitative analyses were performed to evaluate the economic impacts and the operating risk of each Alternative.

Economic Analysis

The results of the quantitative economic evaluations are summarized in Table ES-1.

Table ES-1: Economic Evaluation Summary

	Alt 5 Existing Operations (Base Case)	Alt 4a New Trenched Crossing	Alt 4b New Tunnel Crossing	Alt 6 Abandon Line 5 & Crossing	Alt 1 New Pipeline	Alt 3 Alt Transport (Rail)
Total Construction Cost ($Million)	0.0	27.3	152.9	212.1	2,025.2[a]	907.8[a]
Construction Cost – Michigan ($Million)	0.0	27.3	152.9	183.5	585.8	0.0
Total Operating Costs ($Million/y)	95.0	95.0	95.0	0	225.0 – 165.0[b]	1,220.0
Operating Costs – Michigan ($Million/y)	83.0	83.0	83.0	0	67.5 – 49.5[b]	184.1
Construction Period (y)	0	2	2	1	5	3
System Tariff Superior – Sarnia/Marysville Area ($/bbl)	Oil:1.50, NGL:1.32					
Line 5 Tariff Superior-Rapid River ($/bbl)	NGL: 0.55					
Line 5 Tariff Lewiston-Marysville ($/bbl)	Oil: 0.60					
Levelized Cost New Infrastructure ($/bbl)[c]	0.000	0.009	0.046	0.067	1.628	6.492
Construction Impacts (Michigan)[d]						
Jobs (#)	N/A	413	1,763	2,188	8,110	0
Earnings ($Million)	N/A	21.0	91.3	104.3	369.2	0.00
Output ($Million)	N/A	71.0	328.5	362.1	1,307.5	0.00
Value Added ($Million)	N/A	23.0	93	189.6	395.7	0.00
Government Revenues ($Million)	N/A	1.0	<4.4	<5.0	<17.7	0.00
Operations Impacts (Michigan)						
Jobs (#)	913	913	913	0	399	1,491
Earnings ($Million/y)	45.2	45.2	45.2	0	23.9	84.3
Output ($Million/y)	136.5	136.5	136.5	0	79.7	323.6
Value Added ($Million/y)	80.6	80.6	80.6	0	42.5	173
Government Revenues ($Million/y)	7.17-9.17	7.17-9.17	7.17-9.17	0	6.15 – 11.15	12.15
Local Market Impacts						
Upper Peninsula Propane (Δ Propane Price) Volume: 2-3 kbbl/d	0.00 ¢/gal	~0.00 ¢/gal	~0.00 ¢/gal	~10-35 ¢/gal (seasonal)	~10-35 ¢/gal (seasonal)	~10-35 ¢/gal (seasonal)

	Alt 5 Existing Operations (Base Case)	Alt 4a New Trenched Crossing	Alt 4b New Tunnel Crossing	Alt 6 Abandon Line 5 & Crossing	Alt 1 New Pipeline	Alt 3 Alt Transport (Rail)
Lewiston Connected Producers (Δ Shipping Tariff) Volume: 10 kbbl/d	0.00 \$/bbl	~0.00 \$/bbl	~0.00 \$/bbl	~\$2.40/bbl	~\$2.40/bbl	~\$2.40/bbl
Market Impacts Detroit / Toledo Refinery Impact (Δ Average Cost of Crude Supply)	0.00 \$/bbl	<0.002 \$/bbl	<0.01 \$/bbl	0.76 \$/bbl	0.35 \$/bbl[e]	1.36 \$/bbl[e]
Michigan Consumers (Δ Gasoline Price)	0.00 ¢/gal	<0.01 ¢/gal	<0.03 ¢/gal	2.13 ¢/gal	1.0 ¢/gal[e]	3.8 ¢/gal[e]

Notes:
[a]excludes abandonment
[b]year 1 – year 10
[c]based on 6%/y real discount rate
[d]maximum levels reported due to non-persistence of construction impacts
[e]impacts are after alternative becomes operational and assume Line 5 abandonment is delayed until then; otherwise, impacts are immediate, as with Alternative 6

Using the existing 20-in. Straits Crossing segments as a base case, the levelized costs of new infrastructure ($/bbl) for the various alternatives are presented below in order of decreasing cost.

1. Alternative 3 (Alternative Transport – Rail): 6.492 $/bbl
2. Alternative 1 (New Pipeline Route): 1.628 $/bbl
3. Alternative 6 (Abandon Line 5 and Crossing): 0.067 $/bbl
4. Alternative 4b (New Tunnel Crossing of Straits): 0.046 $/bbl
5. Alternative 4a (New Trenched Crossing of Straits): 0.009 $/bbl
6. Alternative 5 (Existing Straits Crossing): 0.000 $/bbl

The State Market Impacts for each Alternative, relative to the existing 20-in. Straits Crossing are presented below in order of decreasing impacts.

1. Alternative 3 (Alternative Transport – Rail): 1.36 $/bbl Detroit/Toledo Refinery Impact / 3.8 ¢/gal Michigan Gasoline Impact
2. Alternative 6 (Abandon Line 5 and Crossing): 0.76 $/bbl Detroit/Toledo Refinery Impact / 2.13 ¢/gal Michigan Gasoline Impact
3. Alternative 1 (New Pipeline): 0.35 $/bbl Detroit/Toledo Refinery Impact / 1.0 ¢/gal Michigan Gasoline Impact
4. Alternative 4b (New Tunnel Crossing of Straits): <0.01 $/bbl Detroit/Toledo Refinery Impact / <0.03 ¢/gal Michigan Gasoline Impact
5. Alternative 4a (New Trenched Crossing of Straits): <0.002 $/bbl Detroit/Toledo Refinery Impact / <0.01 ¢/gal Michigan Gasoline Impact
6. Alternative 5 (Existing Straits Crossing): 0.00 $/bbl Detroit/Toledo Refinery Impact / 0.00 ¢/gal Michigan Gasoline Impact

Operating Risk Analysis

In the risk assessment of the existing Straits Crossing segments, the principal threats that were found to contribute to the operating risk on the existing 20-in. Straits Crossing segments are, in order of decreasing contribution, anchor hooking, incorrect operations, vortex-induced vibration (VIV), and spanning stress. Of these threats, only VIV is time-dependent (i.e., the magnitude of failure probability increases with time), although as shown in Figure ES-6, the degree to which that time-dependency influences the total (all-threat) annualized failure probability is marginal. Over the 35-year time period of 2018 - 2053 the increase in total (all-threat) annualized failure probability is only 0.4%. As shown in that same Figure, the dominant threat, representing more than 75% of the annualized total (all-threat) failure probability, is that of anchor hooking caused by the inadvertent deployment of anchors from ships traveling through the Straits. The magnitude of the annualized failure probability associated with spanning stresses was found to be below the resolution of the analysis, and so is not depicted in Figure ES-6.

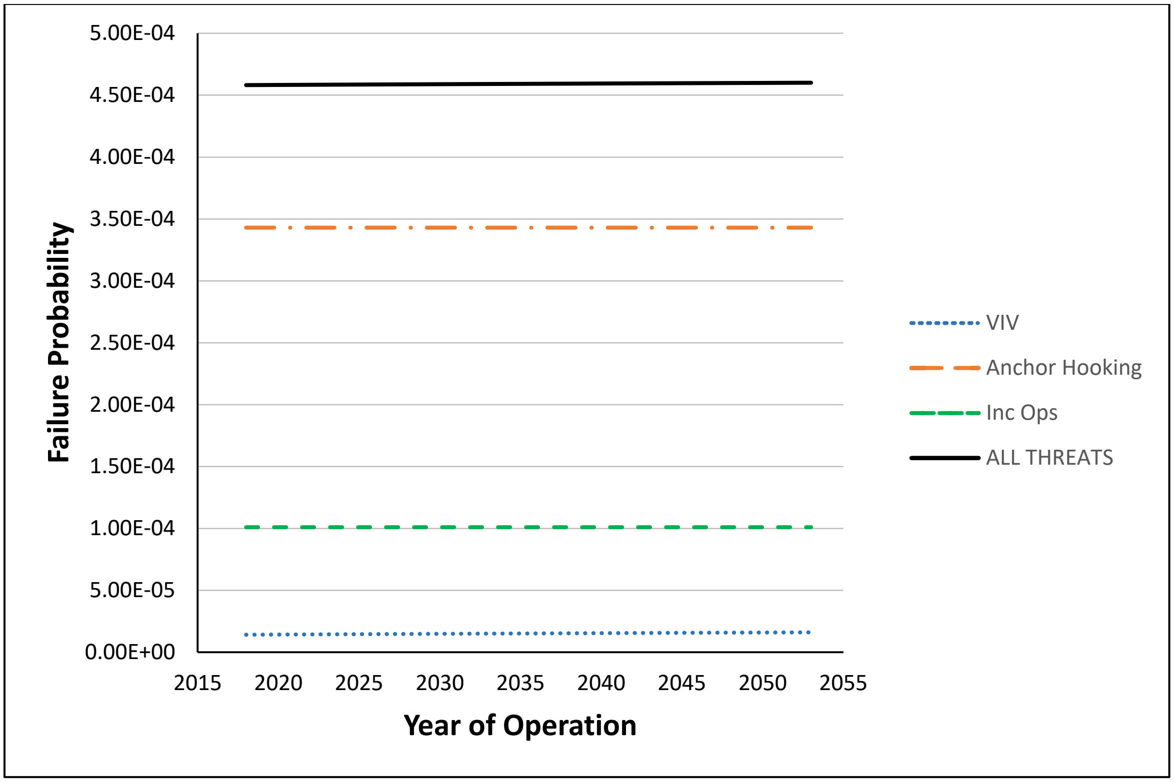

Figure ES-6: Annual Failure Probability Over Time – Existing Straits Crossing Segments

The results of the quantitative risk analysis are summarized in Table ES-2.

Table ES-2: Operational Risk Analysis Summary

	Alt 5 Existing Operations (Base Case)	Alt 4a New Trenched Crossing	Alt 4b New Tunnel Crossing	Alt 6 Abandon Line 5 & Crossing	Alt 1 New Pipeline Route	Alt 3 Alt Transport (Rail)
Principal Threats	Anchor Drag, Incorrect Operations, Spanning, Vortex-Induced Vibration	Anchor Drag, Incorrect Operations	Negligible	N/A	Per Incident Statistics	Per Incident Statistics
Zone of Exposure	Core: Mackinac, Emmet, Cheboygan; Other: Chippewa, Charlevoix, Presque Isle, Antrim, Grand Traverse, Alpena		None	N/A	~762 mi. of WI, IL, IN, MI (MI = ~226 mi)	~800 mi. of WI, IL, IN, MI (MI = ~240 mi.)
Oil Spill Outflow – Rupture (bbl)	2,629	5,859	None	N/A	3,784	Median Spill 462 bbl
Oil Spill Outflow – Puncture (bbl)	N/A	N/A	None	N/A	300	
Oil Spill Outflow – Leak (bbl)	North: 2,902; South: 4527	North: 5,820 South: 9,801	None	N/A	57	
Failure Frequency - Rupture (/y)	3.575x10-04	2.430x10-06	Negligible	N/A	1.84x10-02	2.891
Failure Frequency – Puncture (/y)	N/A	N/A	Negligible	N/A	1.67x10-03	
Failure Frequency – Leak (/y)	1.007x10-04	5.040x10-05	Negligible	N/A	0.187	
Safety Risk (fatalities/y)	2.69x10-06	1.68x10-07	Negligible	0.00	3.66x10-01	2.24
Total Economic Risk ($/y)	41,500[a]	8,870[a]	Negligible	0.00	1,920,000[a]	49,700,000[a]
Monetized Environmental Risk ($/y)	24,900[a]	5,320[a]	Negligible	0.00	841,000[a]	18,300,000[a]
Notes: [a]results may reflect rounding						

Using the existing 20-in. Straits Crossing segments as a base case, the Operating Risk of each of the alternatives is presented in Table ES-3 in order of decreasing risk.

Table ES-3: Risk Multiples (Relative to Base Case) for Alternatives

Alternative	Risk Multiple, Relative to Base Case (Existing Crossing)		
	Safety Risk	Monetized Environmental Risk	Total Economic Risk
Alternative 3 (Rail Transport)	830,000 X Base	734 X Base	1,196 X Base
Alternative 1 (New Pipeline)	136,000 X Base	34 X Base	46 X Base
Alternative 4a (New Trenched Straits Crossing)	0.062 X Base	0.214 X Base	0.214 X Base
Alternative 4b (New Tunnel Crossing of the Straits)	Negligible	Negligible	Negligible
Alternative 6 (Abandonment of Line 5 and Straits Crossing)	Zero	Zero	Zero

Preface

Draft for Comment

This Draft Final Report document presents the results of the *Alternatives Analysis for the Straits Pipeline* This analysis was conducted by Dynamic Risk Assessment Systems, Inc. (Dynamic Risk).

This Draft Final Report document presents findings and analyses based on work conducted from August 2016 forward. This draft is circulated to obtain input, and to refine and elaborate on the analyses before finalization in September 2017. This work is an independent study, contracted by the State, which relates to the Enbridge Inc. (Enbridge) Line 5 System in the United States (US). The results of this draft do not necessarily reflect the positions of the State of Michigan (the State), Enbridge or other stakeholders.

Procedures for Comment

The State has developed a Public Outreach Strategy based on recommendations received by stakeholders and Pipeline Safety Advisory Board members. Comments on this Draft Final Report document may be provided in writing or verbally:

- Submit written comments online at http://mipetroleumpipelines.com/ beginning July 6, 2017.
- Submit verbal comments at (and participate in) the Michigan forums listed next.

Date	Public Information Meeting
July 6, 2017 (Thursday)	Presentation of Draft Report (City of Lansing)
	Public Feedback Sessions
July 24, 2017 (Monday)	Public Verbal Comments on Draft Report (City of Lansing)
July 24, 2017 (Monday)	Public Verbal Comments on Draft Report (Traverse City)
July 25, 2017 (Tuesday)	Public Verbal Comments on Draft Report (City of St. Ignace)

Meeting and session attendees include:

- Authorized and high-level representatives from Michigan DEQ, MAE, DNR and AG.
- State contractor: Dynamic Risk.

Find up-to-date information for this meeting and sessions at:

http://mipetroleumpipelines.com/

Contacts for Written Comments

If for some reason you are unable to provide comment via the web site and are unable attend one of the three feedback sessions to provide comment verbally, feedback on the draft reports can be sent to:

Department of Environmental Quality
Attn: Line 5 Alternatives Analysis
P.O. Box 30473
Lansing, Michigan 48909-7973

Conventions

Language

This report uses the English (U.S.) language.

Measurements

This report uses International System of Units (SI) and imperial units, except for pipe sizes. SI appears first, followed by an equivalent imperial measurement in parentheses. For example, *5,100 mi. (8,208 km)* and *600 psi (4,137 kPa)*, but *20-in. diameter pipe*.

Italics

In this report, italics are used to:

- denote standards, codes, regulations, laws and acts (e.g., the *Interstate Commerce Act*)
- emphasize certain phrases or words (e.g., propane consumers and crude producers are *price-takers* as opposed to *price-makers*)
- indicate the names of existing documents (e.g., *Pipelines Alternative Study*)
- indicate lengthy direct citations.

Footnotes

Footnotes are located at the bottom of relevant pages, above document footers. In prose, a superscripted number identifies a footnote. For example, documented flows to the US Midwest are negligible.[1]

Currency

All currency units in this report are in United States dollars unless otherwise indicated.

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1 Introduction and Background

This *Alternatives Analysis for the Straits Pipeline* (this report) was written by Dynamic Risk Assessment Systems, Inc. (Dynamic Risk) for the Analysis for Straits of Mackinac Pipelines Project (the project) on behalf of the Michigan Department of Natural Resources (DNR), the Michigan Department of Environmental Quality (DEQ), The Michigan Agency for Energy (MAE), and The Michigan Office of Attorney General (AG) – collectively referred to in this report as the State of Michigan (the State) – as part of the State's Public Outreach Strategy. This report is the result of an independent study, contracted by the State. It contains a comprehensive analyses of alternatives to the existing Enbridge Line 5 twin pipelines (Straits pipelines), which are located in Straits of Mackinac (Straits) within the Great Lakes in the United States (US).

This section provides overall background information about the assessment and alternatives. It describes the study process, the general scope, intent of the analyses, and the general type and sources of information used for the analyses. It also introduces the alternatives that were considered. It describes how screening processes were applied to narrow down the alternatives' aspects to those for more detailed impact and risk analyses. Further, it provides a general introduction to the different methodologies and modeling techniques that were applied. In general, where detailed impact and risk analyses are conducted, the methodologies involved assessments associated with the routine construction and operation of an alternative through:

1. logistical assessments and design-based cost estimates
2. socioeconomic impact and screening analyses
3. environmental screening analyses
4. market impact analyses

This section provides some guidance in interpreting the results of these analyses.

In addition, the detailed analyses of hypothetical accidental oil spill risk reflect:

1. threat assessment
2. estimates of outflow or spill size for credible threats
3. calculation of probabilities of specific incidents
4. modeling of the fate of spills in the Straits environment or discussion of the fate of terrestrial spills from pipeline and other alternatives
5. screening and assessment of safety and environmental consequences of these spills
6. screening of socioeconomic consequences of the spills
7. estimate of quantifiable economic consequences, including spill cleanup and damage costs.

1.1 Objective and Scope

As outlined in the State's *Request for Information and Proposals* on February 22, 2016, the overall objective of the work is [1, p. 5]:

> *to provide the State of Michigan and other interested parties with an independent, comprehensive analysis of alternatives to the existing Straits Pipelines, and the extent to which each alternative promotes the public health, safety and welfare and protects the public trust resources of the Great Lakes. The work does not include a recommendation by the contractor of a preferred alternative. Rather, the work includes the development of information that can be used by the State and other interested parties in making decisions about the future of the Straits Pipelines.*

The scope of work contemplated the analysis of these six broadly described alternatives:

1. Alternative 1

   Construct one or more new pipelines that do not cross the open waters of the Great Lakes and then decommission the existing Straits pipelines.

2. Alternative 2

   Utilize existing alternative pipeline infrastructure that does not cross the open waters of the Great Lakes and then decommission the existing Straits pipelines.

3. Alternative 3

   Use alternative transportation methods (e.g., rail, tanker trucks, oil tankers and barges) and then decommission the existing Straits pipelines.

4. Alternative 4

   Replace the existing Straits pipelines using the best available design and technology.

5. Alternative 5

   Maintain the existing Straits pipelines.

6. Alternative 6

   Eliminate the transportation of all petroleum products and natural gas liquids (NGLs) through the Straits segment of Enbridge's Line 5 and then decommission that segment. This alternative would also reflect potential viability of continued NGL deliveries to the Upper Peninsula at Rapid River, and the continued receipt of Michigan light oil production at Lewiston.

1.2 Introduction to Line 5

Enbridge's Line 5 is a 645-mi. (1,038 km), 30-in. diameter pipeline that routes through Michigan's Upper and Lower Peninsulas, originating in Superior, Wisconsin, US, and terminates in Sarnia, Ontario, Canada (see Figure 1-1). As it traverses the Straits, Line 5 splits into two 20-in. diameter pipelines that are buried onshore and offshore to a depth of approximately 70 ft. (21 m). Thereafter, the Straits pipelines lie on top of the lakebed, crossing the Straits west of the Mackinac Bridge – a distance of 4.5 mi. (7.2 km).

Figure 1-1: Enbridge Mainline System – Line 5 Overview

Enbridge has a long-standing practice of transporting light crude on Line 5, including condensate, light synthetic, light sweet crude oil, and NGL volumes. Many shippers rely on the configuration of the Line 5 System in terms of structuring business operations. On the Upper Peninsula, Line 5 delivers NGL to the Plains Midstream Depropanization Facility at Rapid River, Michigan. Propane is extracted from the NGL stream and the depropanized NGL stream is returned to Line 5 for transport to the Sarnia area. On the Lower Peninsula, Line 5 provides receipt of Michigan light oil production at Lewiston – where it interconnects with the Markwest Michigan Crude Pipeline System. Also on the Lower Peninsula, Line 5 delivers crude to the Marysville Crude Terminal (Marysville terminal) that interconnects to the Sunoco Eastern System pipeline, which transports crude from the Marysville terminal to refineries in Detroit and Toledo. Line 5 throughput is delivered to the Sarnia terminal where it is then transported to refineries in Ontario, New York State, and Quebec. NGLs are also delivered to the Plains Fractionation Facility in Sarnia.

1.3 Purpose of Report

The final deliverable for the work is a final report that contains the full findings of the *Pipeline Alternatives Study*. The final report will reflect input received during a review process that has been determined by the State to include public information meetings, Tribal consultations, referrals to Federal agencies, and public feedback through written and oral presentations. This report presents the initial findings of the study, with a view to facilitating the review process.

1.4 Layout of Report

This section provides general background information on the scope, sources of information, alternatives considered, and the methodologies used in support of the analyses that were undertaken. Subsequently, six sections present the analyses and findings associated with the six general alternatives (see Section 1.1). The sequence of these sections differs from alternative numbering for logical reasons:

- Section 1 is an introduction that provides background information about this report.
- Section 2 considers the status quo (Alternative 5).
- Section 3 considers alternative pipeline designs to the existing crossing (Alternative 4).

  (All subsequent alternatives involve partial or full decommissioning of Line 5.)
- Section 4 considers decommissioning (Alternative 6). This alternative appears in this sequence because it evaluates options and illustrates standalone implications of decommissioning the Straits crossing.
- Section 5 addresses the immediate potential response to decommissioning, which is a systemic attempt to use existing capacity by filling or repurposing idle pipeline capacity (Alternative 2).
- Section 6 investigates the construction of a new pipeline to accommodate the mainline volumes previously handled by Line 5 (Alternative 1).
- Section 7 considers non-pipeline options (Alternative 3).

Supporting sections include these appendices:

- Appendix A lists abbreviations (acronyms) used in this report.
- Appendix B lists references used in this report.
- Appendix C is not currently used.
- Appendix D to Appendix R contain additional ancillary information to support the findings in this report. These include methodological discussions, detailed design or analytical assumptions, technical drawings, spill maps, and more detailed results for impacts or consequences.
- Appendix S lists attachments to this report.

1.5 Independent Review

As described previously, this report constitutes an independent review of the alternatives considered. Dynamic Risk was contracted by the State to conduct this review impartially, based on the best available information and the use of best-practice methodologies, that are fit-for-purpose, to permit an objective comparison of the alternatives.

1.6 General Scope

Section 1.1 describes the broad scope of the analysis. This section identifies some of the limits and boundaries that were applied within the scope of the work.

1.6.1 Geographic Focus

Although the study area is broadly considered to be the *Great Lakes Region*, the study focuses on Michigan in assessing the economic and market impacts of various alternatives, and the consequences of spills. In various contexts, information at the Michigan county and township level has been used, and operating *transport corridors* were consistently defined as the contiguous counties through which a pipeline or a rail line would pass. Some impacts were also aggregated to planning regions commonly used in Michigan: these are the Prosperity Regions shown in Figure 1-2. The Prosperity Regions are also used as a basis for reporting some of the economic impacts (jobs and output) of existing Line 5 facilities and alternatives evaluated within this study.

Figure 1-2 also shows the core counties (i.e., Mackinac, Emmet and Cheboygan) that fall within a zone of exposure (ZOE) to hypothetical spill incidents modeled in this study[1].

[1]Outflows and fates of 720 individual spill events were modeled for this study. About 94% of the shoreline oiling and 99% deposition of oil by mass occurred in the core counties of Mackinac, Emmet, and Cheboygan; these three counties are thus the focus of quantitative work relating to spill costs and damages. The full ZOE includes nine counties that may experience impacts from some spills. The neighboring counties of Chippewa, Charlevoix, and Presque Isle also, at times, experienced spill impacts; however, total shoreline oiling was on average 5% of their cumulative shorelines. In Antrim, Grand Traverse and Alpena, the likelihood of a spill reaching shore is very low. The amount of shoreline oiling is also relatively low. The time that a spill takes to reach their shores is typically a week or longer after the event. Michigan counties not included among these nine did not have any shoreline incidences of spills in the 720 hypothetical spill incidents.

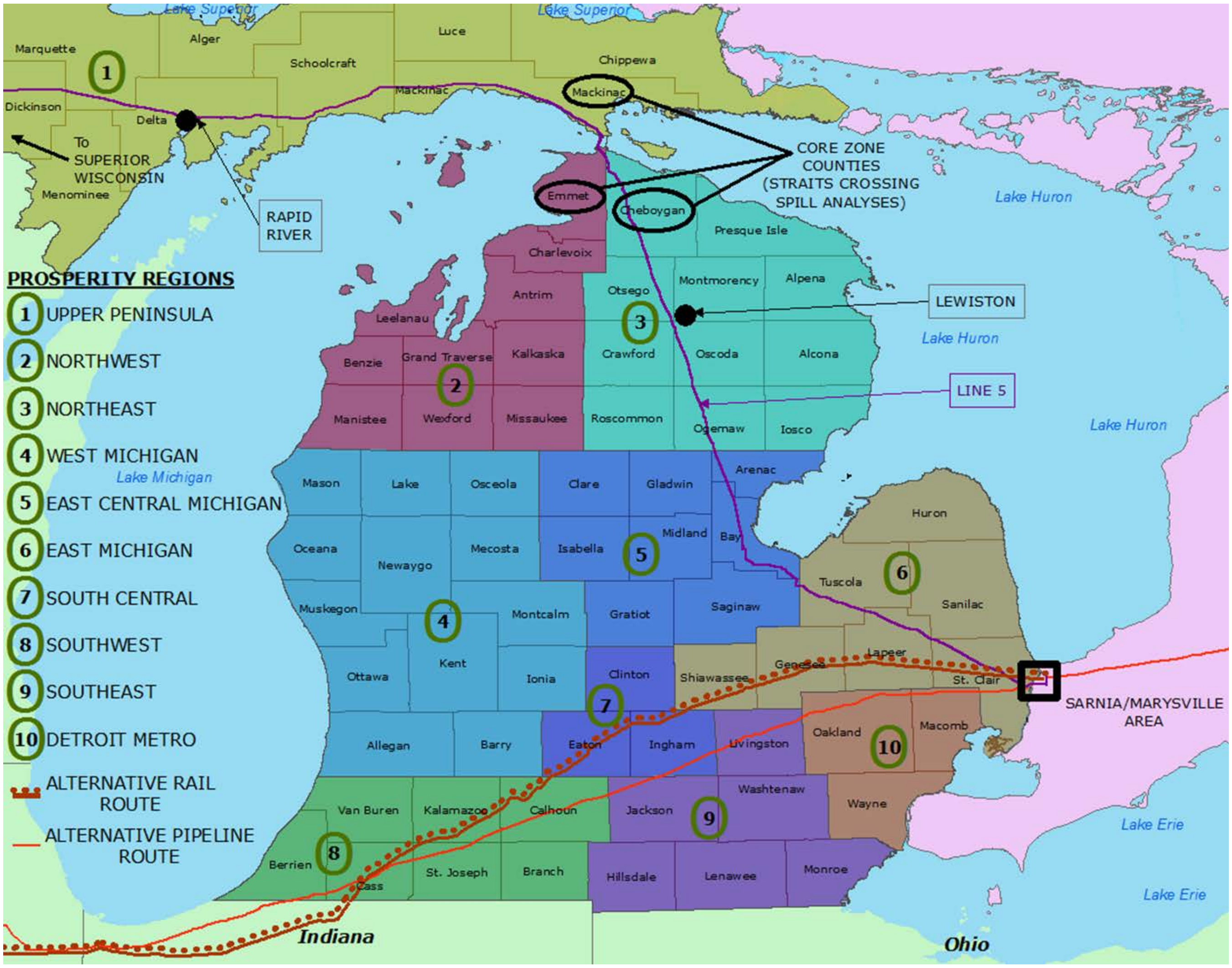


Figure 1-2: Michigan State – Various Geographical Areas of Interest

1.6.1.1 Superior to Sarnia Routing

The analyses generally consider alternatives to the transportation of oil or NGLs from the Line 5 origin in Superior to its terminus in Sarnia. Alternatives that are technically feasible but involve a new crossing of the Great Lakes have been screened out, and are regarded as out of scope. Mixed alternatives (multi-modal transport or combinations of multiple lower capacity alternatives) were not considered. All alternatives were considered, in principle, as a way of replacing the 540 kbbl/d of capacity afforded by Line 5. The screening procedures resulted in five configurations for transporting product from Superior to Sarnia:

1. Alternative 5 – status quo
2. Alternative 4A – new 30-in. pipeline in a trenched crossing at the Straits
3. Alternative 4B – new 30-in. pipeline in a tunnel crossing at the Straits

4. Alternative 1-S – southern routing of a new 30-in. pipeline
5. Alternative 3R-S – southern routing of a rail line.

Full economic impact analyses were undertaken for all these alternatives, in addition to risk analyses associated with their operations.

1.6.2 Primary Data

The study is based on existing information with no primary data gathering or public input on social impacts. A number of the assessments should thus be regarded as *screening* exercises – particularly as they relate to environmental and social impacts of facility construction or operation – or to environmental and social consequences of hypothetical spill events. In these instances, qualitative discussions, selected baseline information, and standard screening tools are provided (see the appendices) to:

- Guide future discussions.
- Assist in identifying potential concerns with alternative configurations.

1.6.3 Recommendations

Per the terms of reference provided by the State, no explicit recommendations are made in the study. Dynamic Risk relied on its own professional judgment to make choices about how some aspects of the alternatives were *screened* for further analyses. Section 1.8 summarizes this screening and it is described in greater detail throughout this report. The discussion also provides some guidance on how some of the results should be interpreted or used. Such guidance is based on methodological considerations; it should not be construed as a recommendation for or against any specific alternative.

1.6.4 Role of Risk Analysis

The risk analyses conducted within this study are regarded as objective assessments of credible threats to existing or new infrastructure. They are *not* intended to represent a worst case spill. They are intended to provide a consistent means for looking into and comparing risks of different operations. The risk analyses include:

- threat assessments
- assessments of potential spill sizes and probabilities of credible spills
- detailed modeling of fates for alternatives involving the Mackinac Straits
- an assessment of economic, safety and environmental consequences.

Economic consequences are described in terms of total spill costs, which include cleanup and quantifiable damages related to socioeconomic and natural resource impacts. Safety impacts are expressed in terms of casualties. Environmental consequences rely on the dollar-based environmental damage assessment within the economic costs. Environmental consequences are further elaborated through a qualitative discussion. Section 1.9.5 provides more detail and elaborates on methodologies used.

1.6.5 Baselines and Treatment of Uncertainty

Other than the projections of failure probability over future time periods, no specific forecasts were undertaken for this work. Conditions in 2016 or early 2017 were generally regarded as a baseline benchmark for costing purposes, and for subsequent economic impact analyses.

For spill modeling in the Mackinac Strait, current and meteorological information from 2014 to 2015 was selected as an appropriate benchmark for simulating a representative range of conditions.

For modeling failure probability from anchor interaction with pipelines, historical vessel traffic through the Straits – spanning 2014 to 2016 – was selected as an appropriate benchmark for representing shipping activity.

Facility costs are characterized as Class 5 estimates, implying uncertainties of -30%/+50%, to reflect design and economic uncertainties. Because the same assumptions and conditions are applicable to all alternatives, comparisons are regarded as unbiased. An overheated economy, for example, would potentially impact all alternatives (at least directionally) in a similar fashion. In addition, economic analyses (for quantifiable socioeconomic impacts, market impacts, and spill consequences) are based on single point estimates for analytical purposes. Uncertainties are addressed through contextual discussion of potential sensitivity of these results, which, in some cases, are quantified. Market impacts are generally quantified and presented as *maximum* expected impacts (in terms of $/bbl or ¢/gallon) on markets given recent market conditions (with qualitative discussions on potential mitigating market forces to such impacts). Sensitivity analyses are provided for selected calculations requiring the use of present value discounting: a 6%/y baseline calculation is provided with sensitivity analyses, as appropriate.

1.6.6 Complementary Analyses

A number of complementary analyses were undertaken as standalone technical or market assessments, which were intended to inform the evaluation of one or more alternatives. These are presented as separate appendices or are integrated within the appropriate sections of this report. Sections 1.6.6.1 and 1.6.6.2 include some of these analyses.

1.6.6.1 Geo-Hazard Assessment

The purpose of the geo-hazard and geotechnical assessment was to investigate factors that could impact the existing crossing or new crossing designs. It provides useful information for the design of new crossing methods for Alternative 4 and risks associated with all of the Straits crossing alternatives. In this respect, the geo-hazard assessment served as a reference to support an evaluation of the threat environment for the existing Straits Crossing segments and the proposed alternative Straits crossing replacements.

1.6.6.2 Propane Supply to Upper Peninsula and Lewiston Injections

Although these issues were included within the scope of Alternative 6, they must be considered in all scenarios involving decommissioning of the Straits pipeline (i.e., Alternatives 1, 2 and 3). A hypothetical scenario was created that involved permanent interruption of Line 5 operations. The background analyses conducted included the volumes involved and likely market response to interruption. It provided a basis for the maximum potential financial impact on propane consumers in the Upper Peninsula and on producers in the Lower Peninsula. Alternatives for small scale transport, generally involving volumes up to 10 kbbl/d, were considered qualitatively and quantitatively. These alternatives included rail, truck tankers, and small diameter pipelines.

1.7 Sources of Information

The study relies on secondary sources of information; field investigations and public input processes that were not included in the scope of the work. Wherever possible, the analyses relied on best available public information, validated through different public sources, professional judgment, or through inspection of confidential information. The study also benefited from access to Enbridge information provided through a series of information requests governed by an agreed protocol between the State and Enbridge. All information requests were submitted in writing to Enbridge by Dynamic Risk and copied to the State. Any communications related to the Straits project between Dynamic Risk and Enbridge were required to be documented in writing.

The contractors acknowledge having had access to some confidential information made available by Enbridge, which is related to Line 5 operations. The contractors are compelled to not release or publish this information in its raw or aggregated form because this involves disclosing (non-Enbridge) third party information designated as confidential. In addition, some information has not been disclosed in precise map or locational formats as it relates to critical infrastructure, which is also protected under the *Critical Energy Infrastructure Information* regulations.

Although Enbridge provided confidential and non-confidential information, wherever possible, the information was validated through other in-house or public sources, or through internal expertise. Except as otherwise noted, all numerical analyses in this report are those of the contractor.

The contractor also relied upon internal in-house models and public databases that were adapted and updated to accommodate recent information. For example, Dynamic Risk models of generic new pipeline risks (Alternative 1 – see Section 6) relied on publicly available information from the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) [2]. Economic impact models relied on publicly available data from the U.S. Bureau of Economic Analysis.

Confidential information on Tribal Trust Lands was provided by the Bureau of Indian Affairs to:

- Assist in identifying routing options that would not conflict with these lands.
- Provide general locational information that might be required in risk assessments associated with spills.

Locational information was considered in the analyses; however, locations are not presented on any maps. Some summary statistics are available based on material previously made public through other consultations. The study does not provide a separate valuation estimate for subsistence, commercial or cultural values associated with the use of resources by tribes. The contractors did not engage in tribal consultations

and acknowledge that ongoing review processes involving the State may provide further input to this work, which would be considered in the final report.

The contractors also acknowledge and thank various government departments and agencies, as well as non-governmental entities, for information they provided.

1.8 Alternatives Considered and Organization of Report

Table 1-1 is an overview of alternatives considered and the styles of analyses applied to each. Table 1-1 is organized in the same order as the sections in this report, which highlights how the analyses were staged and filtered to finalize the configurations for detailed risk analyses, economic impact analyses, and market impact analyses.

Table 1-1: Alternatives Considered

Chapter	Alt ID	Alternative	Type	Description	Design/Logistics (a)			Economic Analysis (b)			Screening (c)		Oil Spill Risk Analysis (d)				
					Screen or Design	Capital Cost	Operating Cost	Levelized Cost $/bbl	Job & Other Impacts	Market Impacts	Environment	Socio-Economic	Threats	Safety Consequence	Economic Consequence	Env'l Consequence	Other
2	5	Alt 5	Existing Routing & Crossing	Line 5 Status Quo	N/A	N/A	✔	N/A	✔	N/A	N/A	N/A	✔	✔	✔	✔	SQD
3	4	Alt 4a	New Straits Crossing	Line 5 New Trench Crossing	Design	✔	✔	✔	✔	Screened	QD	QD	✔	✔	✔	✔	SQD
	4	Alt 4b	New Straits Crossing	Line 5 New Tunnel Crossing	Design	✔	✔	✔	✔	Out	QD	QD	✔	✔	✔	✔	SQD
	4	Alt 4' (e)	New Straits Crossing	Abandon existing twin 20" pipes	Design	✔	N/A	✔	✔	[negligible]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	6	Alt 6a	Decommission Line 5	Partial Decommissioning in UP and/or LP	Screen	Screened Out [Not viable due to operational and integrity issues]											
	6	Alt 6b (e)	Decommission Line 5	Abandon existing Line 5 (including crossing)	Design	✔	N/A	✔	✔	✔	QD	QD	N/A	N/A	N/A	N/A	N/A
	6	Alt 6bUP	Decommission Line 5	Upper peninsula propane supply (Rapid River)	✔ Truck/Rail	N/A	✔	✔	✔	✔	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	6	Alt 6bLP-R	Decommission Line 5	Lower peninsula transportation service (Lewiston)	✔ Rail	Screened Out [No Available rail infrastructure]											
	6	Alt 6bLP-T	Decommission Line 5	Lower peninsula transportation service (Lewiston)	✔ Truck/Rail	N/A	✔	✔	✔	✔	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5	2	Alt 2	Spare Capacity	Use non-Line 5 pipeline capacity	Screen	Screened Out [Capacity Not Available]]											
6	1	Alt 1-N	New-build pipeline	Northern Route (via Canada)	Design	✔	Screened Out [Cost Considerations]										
	1	Alt 1-C	New-build pipeline	Central Route (via Kincheloe)	Screen	Screened Out [Involved New Great Lakes Crossing]											
	1	Alt 1-S	New-build pipeline	Southern Route (via Chicago)	Design	✔	✔	✔	✔	✔	QD	QD	✔	✔	✔	✔	SQD
7	3	Alt 3T	Alternative Modes	Truck	Screen	Screened Out [Logistics Not Viable]											
	3	Alt 3B	Alternative Modes	Barge Duluth-Port Huron	Screen	✔	Screened Out [Cost Considerations]										
	3	Alt 3R-N	Alternative Modes	Rail - Northern Route (via Canada)	Design	Screened Out [Length/Cost Considerations]											
	3	Alt 3R-C	Alternative Modes	Rail - Central Route	Screen	Screened Out [Involved New Great Lakes Crossing]											
	3	Alt 3R-S	Alternative Modes	Rail - Southern Route / No Michigan Terminals	Design	✔	✔	✔	✔	✔	QD	QD	✔	✔	✔	✔	SQD

Notes

(a) Design/Logistics documents preliminary screening or design exercises that were undertaken. Design at times advanced to later stages of full cost estimation before a particular alternative was retained or screened out of further analysis. During some of these screening exercises, the partial analyses were used to select an appropriate scenario for further analysis. For example, rail was screened out as an option for transport of Lewiston production but retained for propane deliveries in the UP.

(b) The economic analyses noted here all included quantitative estimates of impacts. Partial analyses are shown for some cases where job and some other county level impacts could not be estimated due to the small size of the impacts.

(c) Screening tools and exercises were applied that are accompanied by qualitative discussions (QD) for environmental and socio-economic impacts or implications of facilities.

(d) Quantitative oil spil risk analyses are conducted for the indicated alternatives, and are accompanied with qualitative or semi-quantiative discussions (SQD) of some elements of the analysis.

(e) These involve decommissioning of (i) the twin straits pipelines [Alt 4']; or, (ii) all of Line 5 including the twin lines and all pump stations [Alt 6b]. Alt 4' impacts are in addition to those documented in Alt 4a and Alt 4b. Alt 6b impacts are in addition to those of Alt 2, Alt 1, and Alt 3. Alt 6b impacts include those of Alt 4'.

✔ Full Quantitative Analysis
SQD Semi-Quantitative Discussion
QD Qualitative Discussion
✔ Partial Analysis
Screened Out
Not Applicable (N/A)

1.9 General Methodologies Applied

1.9.1 Design-based Cost Estimates

Cost estimates are based on in-house designs and experience with estimating costs for oil industry projects and operations. Each alternative requires a different number and combination of materials, construction, and construction support activities for the proposed infrastructure. The methodology used for each line item across all alternatives was maintained to create a fair comparison wherever possible. Operational costs were also estimated in-house, and were further validated through inspection of public filings to regulators. Final design costs were not generated for configurations that were screened out (these include trucks, a new central pipeline route and a new central rail route). Also, preliminary cost estimates were derived for some designs that were not pursued further because of high cost, other logistical constraints, or both. These included the northern Canadian pipeline route, the northern Canadian rail route, and the articulated tanker barge route (Great Lakes). Detailed cost estimates were prepared for the existing routing (two new crossing methods), decommissioning (existing Line 5 – terrestrial pipeline, facilities, and strait crossing pipelines), and southern rail and pipe alternatives. Line 5 operational costs have been assessed based on in-house and public information.

As noted previously, the design costs are conducted for the purposes of comparing the various alternatives using a common methodology. The costs generally reflect Class 5 estimates, representing an accuracy range of -30%/+50%.

In interpreting the costs, the reader is cautioned that costs are not necessarily directly comparable to other projects. Costs estimated for this study exclude some owner costs (i.e., land costs) and do not reflect optimization that may occur at more advanced stages of design. Also, the design for this pipeline reflects different parameters than other pipelines that may have been constructed elsewhere. For example, the light oils carried by Line 5 generally have lower pumping requirements and pump stations than a heavy oil pipeline.

1.9.2 Economic Feasibility Analyses

Economic feasibility analysis results are the first of three quantitative measures used to assess the various alternatives. Economic feasibility is regarded as an *efficiency* measure in economic terms. In standard economic analyses, it assesses the economic viability of a facility in terms of cost and benefit streams from normal operations: this is traditionally called a social cost benefit analysis. For this study, the alternatives described are designed to provide equivalent capacity and deliveries to that of the existing Line 5. In practical terms, this corresponds to total delivery capacity of 540,000 bbl/d, of which 1/6th is assumed to be NGLs. The project therefore employs a cost-effectiveness analysis to permit a simpler comparison that does not rely on explicitly estimating the benefit streams or revenues from the alternatives. Such a cost-effectiveness analysis is consistent with *OMB Circular No. A-4* (2003), which focuses on regulatory analysis of alternatives [3]. It also serves as an appropriate comparative basis for performing subsequent market impact analyses.

The cost effectiveness analysis is undertaken for each alternative passing the preliminary screening. It is based on the present value of a cash flow profile of capital and operating costs needed to deliver a volume equivalent to that of the current pipeline infrastructure. This volume is selected as a benchmark to permit comparisons of alternatives independent of selected upstream and downstream impacts (which will be addressed elsewhere). The key reported metric is a levelized cost in $/bbl terms. The levelized costs are subsequently used in market analyses to determine the degree to which producers, refiners, and consumers of energy products, may be impacted. A levelized cost can be thought of as the real (excluding inflation) price that must be received for every barrel of throughput over the life of a project for a transportation service to break even. The current Lakehead System toll to transport products from Superior to the Sarnia area is a useful benchmark for comparison: approximately $ 1.50/bbl[2].

For a standalone comparison of alternatives, the levelized costs are calculated based on the design-based cost estimates for each alternative, the throughput of the reference case for Line 5 (540,000 bbl/d), and a real discount rate of 6%/y. Reviewed literature and guidelines in the US and Michigan placed potential positive real discount rates within a range of 2.875 to 10%/y. The specific sensitivity results for this study are shown at 4 and 8%/y. The Michigan discount rate[3] of 5%/y, used for damages, is described in this study but its discounting methodology makes it less appropriate for facility analyses involving interstate systems. However, the results for this Michigan methodology fall within the sensitivity range reported in this study. The reader is cautioned that – in comparing alternatives – it is best practice to use the same discount rate methodology and rate in any such comparisons. The 6%/y real discount rate in the mid-range provides an appropriate basis for such comparisons.

1.9.3 Socioeconomic Impacts

1.9.3.1 Jobs, Income and Government Revenue

Economic impact analysis results are the second set of three quantitative measures used to assess the six alternatives. These results are routinely provided in regulatory settings because they provide information about jobs, incomes, economic output – such as value-added or gross domestic product (GDP) – and government revenue. Such results are impact measures in economic terms and provide complementary information to stakeholders and decision-makers relating to the economic desirability of a project. Impact results are frequently, which is the case here, presented alongside economic efficiency measures. For example, the $/bbl costs associated with the cost-effectiveness analysis – although cost-benefit analyses efficiency measures may include measures such as internal rate of return or net present value.

In interpreting results, remember that:

- Economic efficiency and economic impact measures can move in opposite directions: efficient projects generally have lower costs and therefore lower economic impacts.

  This is the case with the alternatives considered in this study. The most cost-effective projects are the lowest cost projects that deliver a given volume of

[2] The component of the toll from Superior to the Sarnia area can be inferred from either the local tariff or the joint international tariff. Those in effect in May 2017 provide the following results: Local 2017 FERC Tariff 43.22.0 implies USD$ 1.505/bbl to Marysville [199]; International 2016 FERC Tariff 45.12.0 implies USD$1.48/bbl [200].

[3] The Michigan discount rate refers to Michigan Case Law that resulted in an award based on a methodology of using a simple discount rate of 5%. This is in contrast with conventional practice that uses an exponential discount rate. This study uses exponential discounting.

product from the desired origin to the desired destination. These lower cost projects will generally have lower direct economic impact because of the lower level of direct expenditures.

- Economic impact measures are generally described in relation to a specific geographical area.

  This is the case with the alternatives considered in this study. Each assessed alternative is considered over three geographic areas:

  a. A *county corridor* of the Michigan counties through which a given alternative passes (the smallest area).
  b. A *Prosperity Region corridor* of the Michigan Prosperity Regions through which a given alternative passes (an intermediate area).
  c. The State of Michigan (largest area).

  Alternatives falling partially or entirely outside of Michigan are assessed based on the operating or capital cost impacts of that portion of the facility falling inside Michigan. For example, the Southern Pipeline alternative involves new facilities in four states, but only the economic impacts of the facilities in Michigan are assessed. Also, the Southern Rail alternative does not include any terminal facilities in Michigan. Therefore, impacts are primarily associated with operational impacts.

Different styles of models are available for conducting economic impact analyses. These generally fall into two categories:

1. Macro-economic models with non-linear relationships between initial shocks and final outcomes.
2. Input-output models reflecting linear relationships between the initial shocks and final outcomes.

Both models rely on relatively stable economic systems, and shocks that are small in relation to the overall size of the economy in which they occur. The methods employed in this study rely on input-output models, which are regarded as appropriate for an expenditure-based impact assessment. The construction projects contemplated in the alternatives considered herein generally satisfy the required conditions for the State and Prosperity Region corridors. The conditions are also satisfied for operating expenditures within the county corridors. However, results for capital expenditure impacts within the county corridors are subject to greater uncertainty because the scale of the impacts may, in effect, flood local markets at time of tendering, requiring crews to be sourced from outside county areas. The impacts associated with the capital cost expenditure estimates at the county corridor level should therefore be used with caution. The impacts estimated for the largest areas (Michigan or the southern Michigan Prosperity Region Corridor) can generally be regarded as the most robust. The State of Michigan impacts are therefore compared across alternatives for summary purposes.

The final point above is also one of the reasons why the scope of the economic analysis is confined to normal facility operations and construction. Economic impacts (in terms of jobs, income, or output) of industrial accidents or temporary unplanned shutdowns cannot be modeled reliably with a macroeconomic or input-output model. This is because impacts are:

- transient

- potentially large in relation to a local economy
- do not adequately reflect the distortions involved from temporary changes in structural demand for given services.

For example, an oil spill will most definitely generate economic consequences, and result in potentially large expenditures for cleanup and restoration activities. The temporary demand associated with such services, and the sourcing of the services, typically has no precedent within the local economy. Moreover, no form of economic model is likely to properly capture the full range of impacts on jobs, income, and final output. Hence, the economic impact models used in this study are confined to facility construction and normal facility operations: oil spill economic consequences are not addressed using these models. Oil spill consequence modeling is described below; however, it essentially involves estimating the direct costs associated with cleanup and restoration.

The input-output methodology on which this study relies involves the use of US Bureau of Economic Analysis (USBEA) statistics reflected in the second generation of its Regional Input-Output Modeling System (RIMS II) [4] [5]. RIMS II relies on national level economic accounts that reflect the entire US economy in 2007. USBEA updates these accounts using regional level information on a routine basis. This study uses the RIMS II update generated in December 2016, reflecting structural information at a county level that is current for 2015. The project regards the models that are based on RIMS II multipliers to be an appropriate method for comparing the alternatives because they:

- generate internal consistency within the range of alternatives analyzed
- permit comparison of the multipliers, and results generated by this study and other studies within the State. The project also noted:
  - RIMS II multipliers can be applied at the national level for describing impacts of direct, indirect and induced economic impacts in Federal agency spending estimates [6].
  - RIMS II multipliers generate results of direct, indirect and induced economic impacts consistent with US Army Corps of Engineers (USACE) practices for assessing socio-economic impacts of projects [7].
  - RIMS II multipliers have been used by the Michigan Oil and Gas Association in 2016 to estimate the contribution of the oil and gas industry to various counties and prosperity regions within Michigan [8] [9].
  - RIMS II multipliers have been used in other contexts for estimating direct, indirect and induced impacts to measure related topics, such as general training expenditures in Michigan [10] and Class 1 Rail System operations throughout various regions in the US [11].
  - RIMS II multipliers permit more transparent access to information than multipliers used in other studies [6] [12].

Notwithstanding this broad use, the interpretation of the results and the use of the multipliers should follow general guidelines for best practice with such models. These are described in various publicly available manuals relating to RIMS II [5]. As context, the RIMS II systems and multipliers can generate two types of results:

1. Type 1

   Type 1 results provide information relating to *direct* and *indirect* impacts. Direct impacts reflect the direct expenditures associated with a given capital or operating cost. Indirect impacts are the next rounds of impacts arising in related industries to these initial direct impacts. For example, pipeline construction involves direct impacts because of direct jobs and a range of other purchased services and materials. Companies providing the other services and materials in turn generate more indirect jobs, and also purchase services and materials. The models provide an estimate of multiple rounds of such iterations, which converge because of leakages (purchases or hiring outside of the local area). Large closed economies tend to have high multipliers. Small open economies tend to have low multipliers. County multipliers are routinely very small, reflecting a high level of leakage. This study looked at a range of specific multipliers generated for St. Clair County and Mackinac County. It concluded that reporting results at the individual county level (while possible) would not provide a reliable indicator of potential economic activity. Therefore, a corridor approach was adopted.

2. Type 2

   RIMS II also generates Type 2 multipliers. These multipliers distinguish between direct impacts, and *indirect* + *induced* impacts. The difference between the Type 1 results and the Type 2 results therefore generates an estimate of induced impacts. Induced impacts reflect the impacts of spending by households as a result of employment. Simply, the job income itself induces a series of impacts within a local economy because of household purchasing behavior. Again, such multipliers tend to be low for a small economy (such as a county) because spending within the county is not necessarily associated with production within that county. The most robust estimates of induced impacts are therefore at the State level.

In some analyses, researchers or proponents will estimate yet another level of induced impacts associated with government expenditures, super-normal or windfall profits associated with a given activity or project. Although RIMS II multipliers can be used in this manner, the USBEA does not generate such higher round multipliers, nor does the project believe the measurement of such impacts is appropriate within the context of the alternatives considered. The projects and activities investigated within this study are generally either partially regulated or are subject to adequate competition that super-normal profits are not generated. Also, incremental government receipts from project activities cannot be reliably linked to earmarked expenditures. Further, they may simply force out other sources of revenue or be directed to debt retirement, thus having no further induced impacts. Appropriately, this study is limited to the reporting of induced impacts associated with the RIMS II Type 2 multipliers. Because results for Type 1 and Type 2 indicators are presented for each alternative at the three geographic areas (previously identified), stakeholders and decision-makers may choose to interpret these as they see fit. In some decision-making contexts (e.g., near-term business generation or for current-year fiscal projections), it may be appropriate to ignore longer-term induced impacts. Notwithstanding, such induced impacts may nonetheless be useful in other broader, longer-term planning contexts.

To assist in interpretation, however, the *RIMS 2 Manual* makes a number of observations about best practice. The study itself has been guided by these observations in conducting the analyses and presenting the results. Observations are summarized as:

- Local scale impacts of adjacent regions cannot be added. The appropriate method of analysis involves the embedding of areas of interest. This study has embedded county corridors within Prosperity Region corridors, which in turn are embedded within the State's results. For any given small region, the results should be regarded as the maximum likely level of indirect or induced impacts.
- Impacts are most accurate using a *bill-of-goods* approach to estimating impacts. This is especially relevant for large scale potential induced impacts associated with new facility construction. This study has adopted such an approach. This requires estimating an expenditure profile that explicitly reflects direct wage employment and the specific inputs from different industrial subgroups within the national system of accounts. This approach provides the most reliable means for generating induced impacts associated with capital expenditure impacts. Operating expenditure impacts can be similarly distributed across such industrial accounts. the study also adopts this method for all but the smallest expenditure streams (which are allocated to a generic industry code).
- Transient impacts may be overstated. Input-output structures are, by their nature, regarded as relatively stable equilibria, reflecting the development of mature local and regional economies. Transient impacts associated with capital expenditures are less likely to generate permanent business ties (for sustained indirect impacts) or permanent household income (for sustained induced spending). Capital cost impacts should therefore be treated as maximum impacts. In addition, the nature of the multipliers is such that they do not predict the actual timing of the impact beyond the idea that it is over the long-term. The results tend therefore to be most robust for recurrent capital expenditures or for operating expenditures.
- Positive and negative impacts are not symmetric. The addition of an expenditure is not necessarily symmetric with removal of an expenditure. Concretely – within the context of this study – care must be taken in interpreting impacts associated with an existing operation (such as Line 5) with one of the alternatives that would entail decommissioning of Line 5. The negative economic impacts and consequences of job loss will be different than those of the potential positive economic impacts and consequences of new job generation. These effects cannot be monetized, but best practice involves reminding the reader that any analysis of existing expenditures should generally be represented and interpreted as a *contribution analysis*. An analysis of a new opportunity or policy is generally represented as an *impact analysis*. Also, contribution analyses results tend to be more robust than impact analyses because they already reflect the existing structure of the economy.

In summary, although the study presents direct, indirect and induced impacts, the project regards the most robust of these estimates to be the direct and indirect impacts associated with the various alternatives. The project regards the induced impacts to be most robust for operating expenditures. Induced impacts associated with capital expenditures are less certain, but are appropriate for comparing across alternatives or to those from other studies[4].

The final category of economic impacts is that associated with government revenue impacts. RIMS II does not generate such results and does not estimate the induced or similar impacts of such revenues. The study estimates are based on independent assumptions across a series of State tax and revenue sources. Appendix Q presents details. Assumptions are generally associated with impacts on industry property taxes, and consumer sales and income taxes. Severance taxes and corporate income taxes are also discussed.

1.9.3.2 Qualitative Social Impacts

Socioeconomic impacts generally include the quantifiable indicators described above, but also can consist of a wide range of unquantifiable impacts that may be of concern to local stakeholders.

A social impact assessment (SIA) generally requires definition of a project with reasonably high certainty of routing options around a given configuration. With such information in hand, the SIA can follow well-developed protocols in the context of a public participation process. Because this study did not involve primary data collection or public processes, the assessments conducted here are regarded as preliminary *screening* exercises. Such exercises provide initial baseline information, and standard screening tools are provided in Appendix Q to guide potential future discussions and assist in identifying potential concerns with alternative configurations. In the case of environmental impacts, which may have some associated social dimension, a Rapid Impact Assessment Matrix (RIAM) is a commonly used screening tool that allows the transparent recording of the values and judgments made [13] [14]. For social impact screening, the project developed a tool consistent with:

- the procedures developed by the USACE.
- recommendations from the Interorganizational Committee on Guidelines and Principles for Social Impact Assessment [7] [15].

The Committee is a group of social scientists endorsed by the National Oceanic and Atmospheric Administration (NOAA) and tasked to aid public and private interests in their SIA obligations under the *National Environmental Policy Act* (NEPA) and their SIA obligations to public agencies.

1.9.4 Market Impacts

Market impacts are considered when changes to the current system might generate changes in prices within the context of product prices seen in Michigan or elsewhere. These market impacts are not tied to the economic impacts described above; instead, they are more closely tied to changes in the cost of product transportation into a given market area. In some cases, the market area is small and is more readily evaluated. Such is the case with the impacts of curtailment in transportation services for NGLs to

[4]A preliminary comparison of the results from this study to other recent studies shows that the induced impacts the project estimates are generally somewhat lower than those generated by other recent studies. The project attributes this to two factors. First, structurally, the US and Michigan economies are generating fewer jobs per dollar of initial expenditure; this impact is reflected in lower multipliers in the December 2016 release and has been confirmed by USBEA [202]. Second, the study's use of a bill-of-goods approach provides better project-specific estimates of expenditures that correctly reflect the impacts associated with the types of activities analyzed herein.

Rapid River and for Michigan crude production in the Lower Peninsula. In both cases, the study has screened a number of different technical alternatives for providing these services. For example, the existing 30-in. Line 5 could be considered for continued transportation, although at a much smaller throughput, but this would generate operational integrity issues associated with operating a large pipeline at very low flow rates. Other configurations were also considered. The project made the analytical assumption that market forces would, in the near term of service interruption, rely on some combination of trucking and rail for transportation. Incremental costs of these services are translated into potential ¢/gallon impacts for propane consumers in Michigan and potential $/bbl impacts for crude oil producers in Michigan. While, in principle, these market impacts could be spread to other stakeholders (e.g., propane producers or product refiners), for the small volumes involved here – propane consumers and crude producers are *price-takers* as opposed to *price-makers*. The brunt of any changes in delivery or collection costs are thus most likely to be absorbed be these stakeholders. In this context, the calculated impacts on Michigan consumers and producers are regarded as the maximum impacts that would be incurred from such a service interruption. Future market forces may change the dynamics of investment in transportation services (delivering propane and light crude). However, an assessment of such changes would be speculative and, in any event, any potential alternatives still need to be competitive with known existing means of non-pipeline transport of these products.

The assessment of larger market impacts of changes in product delivery are more complicated. The project, again, assesses the maximum anticipated impact on Michigan interests. These interests include primarily consumers of refined petroleum products (RPPs) in Michigan, and those interests associated with the Detroit refinery. The project acknowledges that Michigan's consumers could be impacted by costs borne by other refiners in the US Midwest (notably refineries in the Toledo, Ohio area). Some of the Line 5 crude routes to Canadian refiners, but documented flows of RPPs to the US Midwest are negligible.[5]

The assessment of impacts for any given alternative consists of three separate and largely independent parts:

1. impact of decommissioning decision
2. impact of abandonment costs
3. impact of new facility costs.

In the case of the new crossing methods (e.g., Alternative 4 considers a new trenched crossing or tunnel crossing), only the last of these impacts comes into consideration. This is because the full Line 5 is not decommissioned and only a relatively low level of abandonment costs are incurred for the existing Straits crossing of the twin pipelines. But for all other alternatives, all of these impacts must be considered. As background, Line 5 is part of a broader system of product movement that is regulated as the Lakehead System, which is operated by Enbridge. In simple terms, a product contracted for transport between Superior and the Marysville or Sarnia area, for example, will be transported at a published tariff – the routing choice is up to the operator. Costs are ascribed, not to individual lines, but to the system as a whole (e.g.; system fixed costs

[5]Crude imports and flows between US Petroleum Administration for Defense Districts (PADDs) are monitored by the US Energy Information Administration; Michigan is in PADD 2 (Midwest). These volumes are reported on an ongoing basis and information for 2016 shows annualized (kbbl/d) imports of zero for finished motor gasoline, aviation gasoline, and kerosene [203](16)

such as insurance or corporate overheads are recovered through all system throughput). Market impacts consider the eventual costs on the entire system.

All RPP market impacts in this study represent a total impact reflecting these elements:

- Decommissioning Decision

  A scenario involving decommissioning directly curtails potential throughput of 540,000 bbl/d. This implies that the current Lakehead System costs (less the variable operating costs associated with operating Line 5) must be spread over the remaining available capacity in the system. This impact will potentially increase all tariffs in the system, including the Superior-Sarnia tariff.

- Abandonment Costs

  Decommissioning will also entail abandonment costs (and potential recurrent monitoring costs) associated with Line 5 and its facilities. These would be incurred by the operator and are assumed to be recovered through Federal Energy Regulatory Commission (FERC) regulatory procedures. These costs would also increase tariffs in the system.

- New Facility Costs

  New facility costs have impacts involving substantial uncertainty because they require the assumption that no other market adjustments will occur over a 3 to 5 year period associated with implementation of the pipeline or rail alternatives. For new pipeline facilities that involve decommissioning all of Line 5, costs of these new facilities would be attributed to the entire Lakehead System (although the total capacity of the Lakehead System is again restored to the pre-decommissioning levels). The net impact is thus directionally dependent on the general cost-effectiveness of the new facility. In this context the levelized cost analysis described in Section 1.9.2 provides an important indicator of competitiveness and eventual potential market impact.

The Market Impact results for Alternative 4 configurations to be the most robust (because they do not involve decommissioning).

1.9.5 Spill Risk Analysis

1.9.5.1 Approach to Risk

This study presents the operating risks associated with selected alternatives. Risk is defined as a measure of the probability that a hazardous event (in this case, a hazardous liquid spill) will occur and the severity of the adverse consequences of that hazardous event. Hazardous events of greatest concern to regulators and the public generally involve adverse impacts to public safety and the environment. This report documents three dimensions of risk including public safety, environmental risk and economic risk. This section describes methods used to quantify these risks, including analytical stages involving threat, outflow, and likelihood assessment associated with a pipeline or facility failure.

In all evaluations of risk presented in this report, care has been taken to represent *true* risk, rather than upper-bound estimates. In this respect, a deliberate attempt has been made to avoid the compounding of layers of *worst-case* assumptions in making estimates of spill probability and spill consequence to ensure that results are as realistic as possible. The alternative to adopting this approach would result in unquantifiable levels of risk amplification, leading to results that are inconsistent with expected outcomes.

Risk may be expressed qualitatively, semi-quantitatively, or as has been done in this report: quantitatively. When quantifying risk associated with an installation or piece of infrastructure, it is conventional to represent public safety risk as the expected number of fatalities per year of operation. Similarly, economic risk can be expressed as expected damage costs (dollars) per year of operation.[6] These fully-quantitative representations of risk are possible because both the measures of probability and consequence may be presented in quantitative terms using consistent units of measure.

When considering environmental risk, however, there are challenges that are associated with making quantitative estimates of the chiefly environmental and socioeconomic consequences that are associated with an oil spill. Specifically, environmental consequences may involve short-to-long-term loss of habitat, increased mortality of species, direct or indirect loss of income, direct or indirect loss of recreational opportunities, and aesthetic impacts to the surrounding environment. Each of these may affect individuals differently depending on social background, heritage, the degree of reliance of the environment for livelihood, personal values, etc. Because of this, one person's perspective on the magnitude of a given environmental consequence may be vastly different from that of another. When spills impact culturally important resources, perspectives can diverge significantly.

Therefore, no government agency or regulatory body has established or adopted quantitative measures that are intended to capture all aspects of environmental risk. Nevertheless, for the purposes of characterizing and comparing the environmental risk between the various alternatives considered in this report, by convention, the environmental component of economic consequence has been adopted to represent environmental consequence. This measure of environmental consequence is based on a monetization of the damages, which in principle encompass the following impacts, provided that these impacts can be directly associated with a spill event:

- restoration costs of the natural environment
- a broad range of environmental damages normally included within a natural resource damage assessment (NRDA), including air, water and soil impacts[7].
- net income foregone in the sustainable harvest of a commercial resource
- net value foregone in the sustainable harvest of a subsistence resource, including fisheries.

[6]The use of expected damage costs in monetary terms is also consistent with *OMB Circular A-4* [3], which prescribes the use of quantitative analyses. Specifically (page 40), it states: "Examples of quantitative analysis, broadly defined, would include formal estimates of the probabilities of environmental damage to soil or water, the possible loss of habitat, or risks to endangered species as well as probabilities of harm to human health and safety. There are also uncertainties associated with estimates of economic benefits and costs, such as the cost savings associated with increased energy efficiency. Thus, [analyses] should include two fundamental components: a quantitative analysis characterizing the probabilities of the relevant outcomes and an assignment of economic value to the projected outcomes. It is essential that both parts be conceptually consistent. In particular, the quantitative analysis should be conducted in a way that permits it to be applied within a more general analytical framework, such as benefit-cost analysis. Similarly, the general framework needs to be flexible enough to incorporate the quantitative analysis without oversimplifying the results". From the same source, the Preamble section states (page 1): "This Circular provides the Office of Management and Budget's (OMB's) guidance to Federal agencies on the development of regulatory analysis as required under Section 6(a)(3)(c) of *Executive Order* 12866, 'Regulatory Planning and Review', the *Regulatory Right-to-Know Act*, and a variety of related authorities."

[7]This study involves an ex-ante approach that is appropriate for hypothetical future events, and it closely follows the methodology of an NRDA exercise that also monetizes damages. The main difference is that NRDA is a "bottom-up" ex-post approach that is more correctly applied to an *actual* spill.

The quantified elements of spill cost calculate an expected value of damages contingent upon the occurrence of an initial spill event. All things being equal, cleanup of a large spill will cost more than a small spill. A spill into a degraded landscape will have lower cleanup costs than one in a pristine landscape. A spill cost *function* – or simplified *model* – potentially reflects all of these variables. This study employs such a model, based on spill cost findings from around the world. The model generally breaks down costs into two key elements: direct *cleanup* costs and *damage* costs. Cleanup costs reflect initial response costs. Damage costs potentially include a wide range of socioeconomic and environmental damages.

Recognizing that all aspects of environmental consequence cannot be fully quantified using consistent units, in addition to providing the environmental component of economic consequences, a rigorous description of environmental consequence related to the alternatives is provided in this report for reference purposes.

1.9.5.2 Oil Spill Behavior and Impact Modeling

Oil Spill modeling is the prediction of the spreading, drifting and weathering of spilled oil under varying environmental conditions. A robust three-dimensional (3D) hydrodynamic model, a wave model and wind maps provide the necessary engine to describe the drift of oil particles within the Straits. Temporal and spatial varying environmental conditions over a full year have been modeled to derive a probabilistic map that reveals the potential zone of exposure, probability of oil pollution, and arrival time of a spill onshore within the Straits. Each map incorporates a large number of single oil spill trajectories, which were calculated over a year – with randomly chosen starting dates and times to avoid bias. This is a step beyond the usual guidance on oil spill response plans that often rely on average currents and wind conditions to predict possible oil spills [16].

For events along the southern rail and pipeline routes, the risk analyses consider the entire routes from Superior to Sarnia. The incident risk is assumed to be constant through these respective corridors. Consequences, however, are not constant because of the different land-use types along the routings. Land-use consequences were assessed based on the distribution of high population areas (HPAs), other population areas (OPAs), and environmentally sensitive areas (ESAs). These areas were determined through publicly available information from the National Pipeline Mapping System [17] and the National Wetlands Inventory [18]. Consequence values and likelihoods were based on the distribution of these features along the respective routes.

Economic consequences are described in this report as the consequences associated with a single spill scenario. These consequences may themselves be an average of different impacts; the most common cost adjustment is to reflect impacts within a high consequence area (HCA). HCAs, for the purpose of the spill cost calculation, include HPAs, OPA, and ESAs.

One important relationship reflected in spill impact modeling is that there are scale effects in spill costs: unit costs (in terms of $/bbl cleanup and damage costs) generally decline with increasing spill size. Intuitively, this reflects a number of characteristics of spill economics:

- First, a spill response – like any operation – involves fixed costs and variable costs. With larger spills, the fixed costs are distributed over a larger volume and average costs thus decline.

- Second, regarding spill behavior, either through deliberate spill response efforts (through source control) or from natural features (such as low-lying areas), spill impacts tend to be contained in a specified area. Larger spills often simply result in larger amounts of oil deposited in the same place. This has an operational effect of permitting more rapid removal, which also lowers average costs. Finally, ecosystem responses to oil exposure generally exhibit threshold effects. If these thresholds are breached, then the subsystem may already have suffered total damage and additional oil would not necessarily increase the damages.

1.9.5.3 Interpretation of Quantified Risk Results

For comparison purposes, this report summarizes results in terms of probabilities, fatalities, and expected costs. To provide some guidance and context for the quantitative results appearing in this report, Section 1.9.5.3.1 to Section 1.9.5.3.5 provide relevant reminders that are to assist reader interpretation.

1.9.5.3.1 Event Probabilities

In keeping with common risk practice, probabilities of event risk are expressed in annual terms: a probability of 0.001/y can also be expressed as E-03/y or $1x10^{-3}$/y; this facilitates notation of rare events. It is equivalent to stating “there is one chance in a thousand that an event will happen in any given year”. The notation for *one chance in a million* is 0.000001/y, E-06/y or $1x10^{-6}$/y.

1.9.5.3.2 Contingent Consequences

Discussion of consequences is frequently cast as “if a spill occurs, then ….”. The project emphasizes that the consequences are themselves dependent on the occurrence of a spill event –these are called *contingent consequences*. This distinction is made because the consequences can themselves have a probability distribution of impacts. For example, project modeling showed that:

- Some spills would never reach the shore because of the presence of ice.
- Some counties were far removed from the spill zone, with very few spills reaching them.
- The townships in some of those counties had very low ratios of coastal habitation.

Assuming that:

- a spill has a 90% chance of making it past the ice
- a county has a 5% chance of a spill reaching it
- the county has coastal habitation along 10% of its foreshore.

Given the above assumptions, the consequences of coastal habitation being affected by a spill in that county are 0.90 x 0.05 x 0.10 = 0.0045 and are *contingent upon the spill occurring*. We express this as 4.5×10^{-3} *per spill event*. If the spill itself has a probability of occurrence of 1×10^{-4}/y, then the likelihood of a spill reaching a populated area in that county is 4.5×10^{-7} per year. Such calculations have been used for the screening exercises employed in this study to determine a core consequence area. Impacts outside of this consequence area are not expected to contribute significantly to any assessment of total risk.

1.9.5.3.3 Recurrent Expected Spill Costs

A recurrent expect spill cost is a probability weighted estimate of total economic risk, expressed as $/y. It can be directly compared to other monetary costs such as recurrent capital expenditures, annual operating costs, wages, or tax payments. The main difference is that these *expected spill costs* are not direct expenditures. The comparison of expected spill costs to normal operational costs is valid: both costs represent *expected costs*. However, their underlying probabilities differ. Spills are rare, while probabilities associated with operating costs approach unity: wages and taxes must be paid and will be incurred with near certainty.

1.9.5.3.4 Expected Fatalities

Expected fatalities are a normalized measure of public safety. The fatalities estimated in this study arise as a consequence of a flash fire caused from ignition of an NGL vapor cloud. Again, the consequence is contingent upon a spill occurring, a gas cloud forming, and a gas cloud persisting long enough to encounter a source of ignition in an area where people are present. Modeling of the mid-channel spills, for example, had very little consequence because of the isolation of the event. By contrast and for near-shore spills, there is an impact that potentially involves fatalities, which itself is informed by local expected population densities. In brief, an expected fatality is also a series of probabilities. Expected fatalities are a function of these various probabilities and the final number of fatalities from a single event. Expected fatalities as an annual event does not mean that there are that many fatalities every year; instead, it is a combination of event consequence and annual likelihood.

1.9.5.3.5 Zone of Exposure Risk Maps

Maps are a summary of all spill trajectories with an inherent probability and do not represent the results of a single spill. A single spill will not cover the entire zone of exposure (ZOE).

1.10 Updates and Final Report

As described previously, this draft report reflects information available to June 2017. The final report, planned for release in September 2017, will reflect input received during the review process. In addition, the project will continue to review other information that may become available outside of the review process. This other information will be documented in the final report, and will be referenced if it materially affects any of the analyses or observations contained in the draft report. For example, Enbridge has routine reporting requirements mandated by the regulator (FERC), with some filings expected during the summer months. Information from these filings will be reviewed and incorporated, as appropriate.

As mentioned previously, for reasons of convenience, cross-reference, and quality control, the numbering of alternatives currently does not represent the order in which they are presented in this report. Alternative 5 represents the normal operation of the existing Line 5 configuration and reflects the original numbering of alternatives in the

State's terms of reference. Alternative 5 appears first in this report's overall outline (see Section 2) because it represents the status quo. Thus, it is a baseline for other alternatives considered in this report.

2 Alternative 5

2.1 General Description

Alternative 5 considers the operation of the existing (original 1953 construction) twin 20-in. diameter Straits Crossing segments, under the assumption that Enbridge's existing operating and maintenance programs continue on a go-forward basis.

The analysis undertaken as part of this alternative includes a comprehensive engineering study of the current condition and operation of the existing pipeline segments based on an evaluation of design, materials properties, installation procedures, operating conditions, as well as a review of Enbridge's assessment data and integrity standards. The analysis includes an evaluation of the safe and reliable operating life of the crossing segments, and the expected influence of time-dependent degradation mechanisms on the integrity of the pipeline segments over time.

The analysis completed for this alternative serves as a *base case* risk assessment and economic evaluation against which all other alternatives may be compared.

2.2 Baseline Conditions and Assumptions

2.2.1 Line 5 Corridor

The Line 5 right-of-way (ROW) enters Michigan in Gogebic County, traverses the southern half of the Upper Peninsula to Mackinac County from where it crosses the Straits to the Lower Peninsula (see Figure 1-1). From Emmet and Cheboygan counties, the pipeline passes through Prosperity Regions 2, 3, 5, and 6, on a southeast route around Saginaw Bay to St. Clair County. In total, the pipeline ROW intersects 19 counties – with a combined population of 917,304, representing 9% of the state population of 9.9 million (2015) [19].

Proximate to the Line 5 ROW, various facilities are associated with Line 5 operations. In the Upper Peninsula, pump stations and associated facilities form part of operations at Gogebic, Iron River, Rapid River, Manistique, Naubinway, and St. Ignace. In the Lower Peninsula, pump stations and associated facilities are at Mackinaw City, Indian River, Lewiston, West Branch, North Branch and Marysville. Also, Gould City and Bay City are home to a terminal and tankage facility. In total, the Prosperity Regions 1, 2, 3, 5 and 6, through which Line 5 passes, have a combined population of 2.23 million. Appendix Q provides additional demographic information relating to counties along the Line 5 ROW.

American Indians have a strong presence in the Upper Peninsula Line 5 corridor counties, where tribal trust land exists in all but two (Dickinson and Iron) of the ROW counties. Compared to the Lower Peninsula, county populations of American Indians are higher in the Upper Peninsula. For example, in Mackinac and Schoolcraft counties, the American Indian population as a percentage of county totals is, respectively, 17.1% and 9.2%. In the Lower Peninsula, only two counties on the Line 5 ROW have tribal trust land: Emmet and Arenac. In Emmet, at 3.7% American Indians represent a relatively high percentage of the population. In Arenac, American Indians represent 1.3% of the county total, which is more in line with their relative populations in other counties of the state. [19]

The average poverty rate in the counties along the pipeline ROW is 15.6%, with the highest rates found in Prosperity Regions 3 and 5, where some counties have rates of 20% (Oscoda and Arenac, for example). For Michigan as a whole, the average poverty rate is 15.8%. The average annual unemployment rate in the ROW counties is 7.4%, which is considerably higher than the state average of 4.9%. The average annual unemployment rate in the counties adjacent to the Straits – Mackinac, Emmet, and Cheboygan – is 8.6%. However, unemployment in these three counties is strongly seasonal because of that area's dependency on tourism. In the recent 2016-2017 period, the combined average monthly unemployment rate for the three counties swings from a low of 4% during the warmer months (May-October) to a high of 14% during the colder months (November to April). [19] [20]

2.2.2 Volume Assumptions

A comparison of the alternatives required the use of consistent reporting and analysis volumes for product being transported. This section summarizes the assumptions used and briefly describes the basis for these assumptions. All these assumptions can be inferred and validated based on publicly available information sources.

All analyses of Line 5 throughput refer to its capacity of 540 kbbl/d. As noted previously, the products transported include NGL and light oil. Throughput varies by location because of deliveries and re-injection of NGL at Rapid River, and injection of light oil at Lewiston. For analytical purposes, this study assumes that Line 5 is operating at full capacity. Enbridge's description of Lakehead System capacity (which includes Line 5 and other pipelines as shown in Appendix F – Enbridge System Overview) shows capacity at the beginning of 2016 into Superior to be 2,665 kbbl/d and capacity out of Superior to be 2,456 kbbl/d [21]. Also, Enbridge's February 2017 U.S. Securities Exchange Commission (SEC) 10-K filing for the 2016 financial year indicated system throughput of 2,574 kbbl/d [22]. Moreover, in its SEC 10-K filing (page 7) Enbridge notes:

> *Based on growth in Western Canadian and Bakken crude oil supply and Lakehead operational performance improvements, deliveries on our Lakehead system are expected to grow beyond the 2.6 million Bpd of actual deliveries experienced during 2016.*

These figures generally suggest a system at full capacity. Because of net withdrawals in the Upper Peninsula and injections in Lewiston, volumes at the Straits are normally expected to be slightly less than 540 kbbl/d – even if the pipeline is operating at full capacity (normally the full capacity point would be downstream of Lewiston).

For analytical purposes, the project assumes that the NGL throughput of Line 5 is 90 kbbl/d. This is based on in-house estimates of apportioned demand to final customers and the nameplate capacity of refiners, receiving pipelines, and NGL fractionation facilities in the Sarnia, Detroit, and Toledo areas (see the Apportionment table in Appendix J). Also, Enbridge SEC filings indicate system NGL throughput of 83 kbbl/d [22]. For alternative facility design and spill consequences we thus assume that any alternative will be transporting NGL 1/6th of the time, and light oil 5/6th of the time. Line 5 does not carry heavy oil or diluted bitumen [23].

It is assumed that propane demand of 3 kbbl/d is supplied to Upper Peninsula customers from the Rapid River facility in winter months. This assumption relies on estimates associated with propane supply interruptions during the State-declared emergency in

January 2014, when a one-million-gallon shortage was experienced over an eight-day outage at Rapid River [24]. Seasonal and annual loads documented in the *Michigan Energy Appraisal Winter Outlook 2016-17* [25] – coupled with considerations relating to propane storage possibilities by households – suggest these peak estimates are consistent with an average annual propane demand of 2 kbbl/d. NGL deliveries to US customers by Enbridge are documented as 5 kbbl/d in its February 2017 SEC filing [22]. The potential delivery points to US customers within the system include Line 1 offloaded deliveries in Superior and Line 5 deliveries in Rapid River.

Assumptions relating to injections of light oil at Lewiston rely on an in-house analysis of well production data associated with counties and fields that are connected to the Markwest Pipeline System FERC Tariff 8.18.0 (effective April 15, 2017) [26], and to well production records in adjacent counties that might take advantage of truck transport to injection facilities at Lewiston. The State maintains well production records and they are available in an open database from the Michigan DEQ [27]. These records were sampled for 2016 to validate accuracy and were summarized through publicly accessible services available through DrillingEdge [28]. Based on these records, the project estimates that over a six year period ending in 2015 – of an average 18,582 bbl/d of Michigan production – approximately 5,045 bbl/d is associated with counties connected to the Markwest pipeline and an additional 4,910 bbl/d is associated with neighboring counties (see Figure 2-1). From these estimates and for modeling purposes, the project assumes that 10 kbbl/d of light oil is injected at Lewiston. The project relies on records up to 2015 because some records for 2016 may still be incomplete. Volumes for 2016 are likely to be below this level. Michigan production, as a whole, has been in a long-term general decline. The 10 kbbl/d is regarded as an appropriate benchmark volume for the purposes of this study.

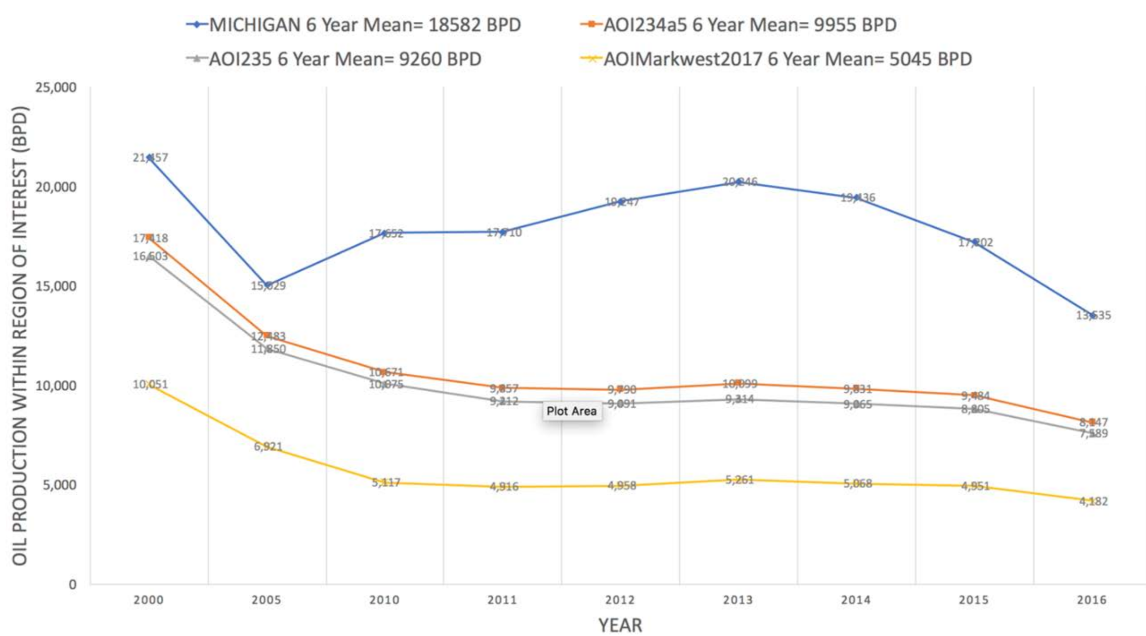


Figure notes:
1. AOIMarkwest2017 includes wells from counties listed in Markwest April 2017 Tariff.
2. AOI235 includes counties from Prosperity Regions 2, 3 and 5.
3. AOI234a5: includes counties from Prosperity Regions 2, 3, 5 and 4a.
Source: Dynamic Risk Estimates [11]

Figure 2-1: Michigan Oil Production

2.2.3 Tariffs

Canadian and US domestic crude from both Western Canada and the Bakken in North Dakota are transported eastward on the Enbridge Mainline System using a batched system to retain commodity integrity and shipper ownership for a wide variety of grades and types of crude petroleum, as well as a mixed stream of NGLs. Line 5 forms part of the Enbridge Mainline System, which is regulated by the National Energy Board (NEB) in Canada and the FERC in the US. Appendix F provides details on the operational modalities of the system and its various interconnection points. The transport of products is regulated according to product characteristics, with origin and destination waypoints serving as a basis for determining fair and equitable tariffs for the transport of those commodities. A tariff is a cost-of-service structure, the revenue from which is intended to cover an operator's return on capital invested, all operational costs, and other costs as may be determined to be fair. Such other costs may include anticipated future abandonment costs, costs incurred because of events beyond the operator's control, or recovery of costs incurred associated with accidents.

Tariffs are routinely reviewed and updated to reflect operating conditions. Tariffs are expressed in terms of $/unit transported and are thus also determined to some degree by system throughput and the efficient use of the system. Because some system costs are fixed, a higher throughput permits reduction in tariffs. Conversely, decreasing throughput on an existing system would normally increase tariffs if the decline in throughput persists. Some throughput interruptions (such as maintenance outages) are planned, while others are not.

Enbridge describes its system as extremely complex, transporting more than 50 distinct types of crude oil and other commodities for more than 100 separate shippers on multiple lines. Individual segments of the Mainline System transport specific commodities, and the allocation of commodities to these pipelines depends on several factors, including but not limited to petroleum quality, supply, tankage constraints, connectivity, receipt and delivery patterns, pro-rationing, and power costs.

Shippers submit monthly nominations for service on the Enbridge Mainline System by advising Enbridge of the origin point, delivery point, volume and grade of crude oil to be shipped. Shippers do not specify which line is to be used for transporting crude to downstream delivery points. Enbridge unilaterally assigns nominations to the pipeline segments. If shippers tender more crude oil than can be transported, Enbridge will apportion such tenders on a *pro rata* basis among the shippers, based on the tenders and current operating conditions of the system.

Typical tariffs for the Mainline System are shown in Appendix F. For shipments from Superior to the Sarnia/Marysville area there is no independent tariff that applies just to Line 5: tariffs are based on origin and destination, not on the specific route followed. For NGL shipments delivered to Rapid River or oil shipments received at Lewiston, there is a standalone tariff. Table 2-1 presents the current tariffs.

Table 2-1: Current Tariffs

Origin – Destination	Natural Gas Liquid	Light Crude Petroleum
Superior – Sarnia/Marysville area	International border near Marysville: $8.2818/m^3 ($1.317/bbl)	International border near Marysville: $9.1732/m^3 ($1.458/bbl) Marysville/Stockbridge: $9.4691/m^3 ($1.505/bbl)
Superior – Rapid River	$3.4331/m^3 ($0.546/bbl)	Not applicable

Origin – Destination	Natural Gas Liquid	Light Crude Petroleum
Lewiston – Sarnia/Marysville area	Not applicable	International border near Marysville: \$3.6224/m^3 (\$0.576/bbl) Marysville: \$3.8904/m^3 (\$0.619/bbl)
Notes: Based on 2017 FERC Tariff 43.22.0; International 2016 FERC Tariff 45.12.0.		

The Superior-Sarnia/Marysville area tariffs shown in Table 2-1 are based on differentials benchmarked at the international boundary near Neche, North Dakota. The differentials may vary slightly for products which have taken a different route to Superior, such as via Clearbrook, Minnesota.

Analyses in this report are generally based on a:

- \$1.50/bbl cost of service for crude from Superior to Sarnia/Marysville area
- \$1.32/bbl cost of service for NGL from Superior to Sarnia area
- \$0.55/bbl cost of service for NGL from Superior to Rapid River
- \$0.60/bbl cost of service from Lewiston to Sarnia/Marysville area.[8]

2.2.4 Line 5 Operating Costs

Line 5 operating costs are based on in-house estimates and an allocation of various system fixed costs based on FERC filings by Enbridge [29]. These operating costs should not be confused with a tariff calculation: a tariff is a cost recovery mechanism. The annual expected revenue from the tariff is approximately \$290 million, corresponding to \$43 million from the NGL stream and \$246 million from crude shipments. By contrast, the recurrent expenses of Line 5 operation are estimated to be \$95 million/y. Recall that the tariffs are system tariffs, which recover system-wide operating costs and a return on past capital investments.

2.3 Socioeconomic Impact of Line 5 Operations

Alternative 5 is the status quo. The operation expenses of Line 5 thus create no *new* socioeconomic impacts because Line 5 operation is ongoing. However, an analysis of Line 5 operation has been undertaken to estimate the pipeline’s current economic contribution (jobs, income, output) to Michigan. In addition, region-specific economic multipliers (to account for spending leakages) are used to estimate the potential economic contribution of Line 5 to those sub-regions closest to the pipeline (ROW counties and Prosperity Regions 1, 2, 3, 5, and 6).

Potential socioeconomic impacts typically associated with a new project – changes to community resources, population impacts, etc. – are not discussed under Alternative 5 because no change in economic activity is associated with this *status quo* alternative.

[8] The tariff for Lewiston injections reflects the potential receipt of Michigan medium and heavy specification crude petroleum at Lewiston for delivery to the Sarnia/Marysville area, and to West Seneca, New York. The heavy oil tariffs from Lewiston to West Seneca, however, are up to 30% higher than the tariffs reported here. This report, however, focuses on the light oil tariff as representative of product carried by Line 5.

2.3.1 Economic Impacts of Alternative 5: Status Quo

Economic multipliers (BEA RIMS II) were used to estimate the economic contribution of Line 5 operation expenses to Michigan, to the Prosperity Regions and counties through which the pipeline passes. Of the total estimated operating costs of $95 million/y, operation expenses of the Michigan portion of Line 5 are estimated to be $83 million/y: these amounts include routine annual replacement capital expenditures for maintaining pipeline integrity (see Table 2-2). The US BEA does not endorse the results or this report's interpretation of the results (see Appendix O for caveats).

The analysis indicates that operation of Line 5 currently contributes to the Michigan economy by generating about 900 (full- and part-time) jobs. Some 250 people are employed directly by Line 5 operations, and another 660 jobs result from the indirect spending on materials and services by supply contractors to Line 5 operations, and induced spending by employees of both Line 5 and its suppliers. Total employment earnings associated with operations are in the order of $45 million/y for all of Michigan. Total output generated by Line 5 operation is estimated at $137 million/y, for a value added of $81 million/y to Michigan as a whole.

Detailed results (see Appendix Q) show that the corridor counties could account for as many as 600 of the 900 jobs, and for as much as $31 million/y of employment earnings. The larger area – the Prosperity Regions – could account for as many as 700 of the jobs, and related earnings of $37 million/y.

Table 2-2: Alternative 5: Economic Contribution of Line 5 Operation Expenses

Alternative 5: Operation Expenses of Line 5			
Operation expenses (includes routine annual capital expenditures)			$95 million/y
Operation expenses in Michigan			$83 million/y
Impact Area	Employment (jobs)	Labor Earnings (million $/y)	Output (million $/y)
Michigan			
Direct	252	22.5	77.0
Indirect	302	10.0	22.4
Induced	359	12.7	37.1
Total contribution	913	45.2	136.5
Value Added currently contributed to Michigan: $81 million/y			
Notes: Economic contribution results were derived using BEA RIMS II multipliers.			

The contribution of this alternative to government revenue is estimated to be $2.18 million/y through consumer income taxes, sales taxes, and transportation fuel taxes. In addition, $5 to $7 million/y are estimated to accrue from pipeline and related facility taxes.[9] This estimate is for Michigan as whole, and is not attributed to counties or Prosperity Regions within the state.

[9]Pipeline taxes are an approximation based on estimates derived from current taxes plus an amount associated with ongoing replacement capital expenditures associated with Line 5.

2.4 Risk Assessment of Pipeline Failure

Risk is defined as a measure of the probability that a hazardous event will occur and the severity of the adverse effects of that hazardous event. In the transportation of hazardous liquids by transmission pipeline, these hazards are considered to be precipitated by a loss of containment. The degree to which a loss of containment of hazardous liquids can present itself as a hazard to either the environment or to public safety is a function of various factors, including:

- quantity of product released:
  - release rate (influenced by operating pressure, hole size, product flow rate and product properties)
  - leak detection capabilities
  - isolation response time
  - spacing of isolation valves
  - elevation profile.
- product properties:
  - vapor pressure
  - flammability
  - heat of combustion
  - density
  - toxicity
  - persistence in the environment.
- environmental factors:
  - presence of surface or ground water
  - degree of environmental sensitivity
  - weather and climactic conditions
  - land use
  - population density.

Enbridge's Line 5 has the capacity to transport up to 540,000 bbl/d of light crude oil and light synthetic crude – referred to as low vapor pressure products (LVPs) – and natural gas liquids (NGLs), including propane. The range of physical properties that characterize this product influence the hazards that must be taken into consideration in a risk assessment. The operating risk of the pipeline over time is, in part, a function of the proportion of time that the pipeline transports LVPs vs. high vapor pressure products (HVPs). Each product type is characterized by the way that a release would impact the environment and safety.

For each operating configuration of LVPs and HVPs, risk is determined as the expected frequency and magnitude of release (failure probability), and the consequences (both safety-related and environment-related) associated with a release.

2.4.1 Failure Probability Analysis

The magnitude of the potential impact associated with a hazardous liquids pipeline release is a function, in part, of the size of the opening associated with the pipeline failure. Therefore, the determination of failure probability is tied to hole size (release magnitude), with different failure rates assigned to each hole size considered.

Regardless of release magnitude, the likelihood of failure is related to the threats (potential causes of loss of containment) that apply to a given segment. A *Threat Assessment* was undertaken to establish the vulnerability of the existing pipeline to each potential threat mechanism, based on attributes of design, materials, operating conditions and environment, as well as a review of assessment data and integrity standards. Because certain threats are preferentially associated with a specific range of hole sizes, the *Threat Assessment* provides a basis for estimating the frequency of releases of a given magnitude.

While some threats, such as geotechnical hazards (which are associated with localized geotechnically-active sites) or shipping hazards (which are associated with shipping lanes) manifest themselves at discrete sites, other threats are present along the entire length of a pipeline. For these threats, the probability of failure over a given time period is proportional to segment length, with longer segments being associated with greater probabilities. While failure probability associated with discrete threats can be quantitatively expressed in terms of failure probability per year of operation, the failure probability for other threats is conventionally expressed on a length-normalized basis (i.e., probability of failure per mile per year of operation).

2.4.1.1 Methodology

Quantitative estimates of failure probability were derived based on a two-step analysis. The first step involved a *Threat Assessment* (described in Section 2.4.1.1.1) in which the vulnerability to each of a number of potential threats were determined. As part of the *Threat Assessment*, approaches for quantifying threat-specific failure probability were selected, giving consideration to threat attribute data, as well as best practice methodologies. Using these approaches, threat-specific quantitative estimates of failure probability were then generated in the second step of the analysis – the probability analysis (described in Section 2.4.1.1.2).

2.4.1.1.1 Threat Assessment

The primary objective of the *Threat Assessment* was to review the attributes for all potential threats to the Straits Crossing pipelines by considering the attributes of each of the potential threats as they relate to the Straits pipelines. Through this review, the relevance and severity of each threat was assessed in consideration of the design, materials, installation and operating conditions associated with the Straits Crossing pipelines.

As a variety of failure likelihood estimation techniques exist, with each requiring specific data sets, the *Threat Assessment* also considered the availability and type of data for each threat to assist in the selection of the optimal approach of determining the failure probability associated with each relevant threat.

The *Threat Assessment* has been structured as follows:

- Section 2.4.1.1.1.1 – Scope

  Description of the pipeline segments and operating conditions.
- Section 2.4.1.1.1.2 – Threat Assessment Approach

  Identification of the threats considered and a description of the approach.
- Section 2.4.1.1.1.3 – Assessment of Threats

  Review of all threat attributes and an assessment of threat potential.
- Section 2.4.1.1.1.4 – Threat Potential Summary

  Summary of the threat potential for each threat, as well as description of the candidate approaches for estimating failure probability based on the availability, quality, and completeness of the data attributes for each threat.

2.4.1.1.1.1 Scope

The Threat Assessment was conducted for the twin 20-in. diameter Straits Crossing pipelines. The design details of these pipeline segments are summarized in Table 2-3 [30], [31], [32].

Table 2-3: Straits Crossing Segments Design Details

Parameter	Value
Diameter (in)	20
Wall thickness (in)	0.812
Material specification / grade	API 5L Grade B (35 ksi yield)
Pipe manufacturing process	Seamless
Name of pipe manufacturer	National Tube
Year of installation	1953
Coating type	Coal tar enamel
Maximum operating pressure (psi)	600
Hydrostatic test pressure (psi)	Installation test (while floating on pontoons) to 1,200 psi. for 5 hours. Post-installation test to 790 psi. for 4 hours (west line) and 12 hours (east line)
Length (ft)	20,434

The Straits crossing segments are bounded by remotely-operated isolation valves located at the North Straits Station and at Mackinaw Station at each side of the Straits crossing, separated by 3.87 miles [33]. Upstream of the Straits Crossing, monitoring equipment is located at the North Straits Station, with one flow meter and two pressure transmitters on the east and west legs of the Straits Crossing pipelines. Downstream of the Straits Crossing, monitoring equipment is located at Mackinaw Station, with two suction pressure transmitters on the east and west legs of the Straits Crossing pipelines. In addition, two pressure transmitters are located on the discharge side of the station, and one pressure transmitter is located on the mainline downstream of the discharge sending trap. A flow meter is also located on the discharge side of Mackinaw station [34].

Launching and receiving facilities for sending and receiving inspection and other tools are located at the North Straits and Mackinaw stations. Both the East and West crossings of the Straits pipelines have been subjected to active and ongoing in-line inspection programs, with high-resolution axial magnetic flux leakage (MFL) and geometry inspections conducted every five years since 1998. Axial MFL inspection covers the full circumference of a pipeline to identify and measure volumetric wall loss, such as corrosion, whereas geometry tools identify and measure dents, ovalities and deformation strain. In addition to MFL and geometry inspection, both the East and West Straits pipelines were inspected in 2014 with ultrasonic tools using time of flight diffraction (TOFD), phased array (PA) pulse-echo and ultrasonic shear wave technologies for circumferentially-oriented cracking.

2.4.1.1.1.2 Threat Assessment Approach

API 1160 – Managing System Integrity for Hazardous Liquid Pipelines [35] lists 12 potential threats that should be assessed for the operation of hazardous liquids pipelines, as follows:

1. external corrosion
2. internal corrosion
3. selective seam corrosion
4. stress corrosion cracking (SCC)
5. manufacturing defects
6. construction and fabrication defects
7. equipment failure (non-pipe pressure containing equipment)
8. immediate failure due to mechanical damage
9. time-dependent failure due to resident mechanical damage
10. incorrect operations
11. weather and outside force
12. activation of resident damage from pressure-cycle-induced fatigue.

As noted in API 1160, not each of the above 12 threats may necessarily apply to the pipe segment being considered in the risk evaluation, and so guidance is provided in Annex A of that document with respect to how the attributes of each threat may be evaluated to assess vulnerability. As the scope of the risk assessment being performed under Alternative 5 is limited to the twin 20-in. pipeline crossings of the Straits, the evaluation of threat attributes for each of the above potential threats was conducted as they relate to those pipelines.

The Threat Assessment was based on a review of attributes for each threat category as outlined in API 1160 Annex A, augmented with a review of threat attributes outlined in ASME B31.8S Appendix A [36].

In pipeline risk assessments, it is often found that certain threats dominate the overall threat environment, with other threats contributing to overall failure probability at levels that are orders of magnitude below, and within estimation error of, the most dominant threats. With this in mind, and as the goal of the *Threat Assessment* was to support a quantitative estimation of failure probability, threats were categorized as:

- Principal Threats

  Threats for which an evaluation of susceptibility attributes indicates a significant vulnerability, and that have the potential to provide the most significant contributions to overall failure probability.

- Secondary Threats

  Threats for which an evaluation of susceptibility attributes indicates a relatively insignificant or non-significant vulnerability and that therefore have the potential to contribute only at a second-order or potentially negligible levels in terms of overall failure probability.

2.4.1.1.1.3 Assessment of Threats

Using the threat attribute guidance provided in API 1160 Annex A, augmented with a review of threat attributes outlined in ASME B31.8S Appendix A, an evaluation of each threat attribute associated with the threats listed in Section 2.4.1.1.1.2 is provided below.

2.4.1.1.1.3.1 External Corrosion

A summary of the threat attribute review and assessment for the threat of external corrosion as it relates to the Straits crossing pipelines is provided below.

2.4.1.1.1.3.1.1 Coating Type

The Straits Crossing pipelines were coated with coal tar enamel (CTE) coating. CTE coatings were used extensively in the North American pipeline coatings market from approximately 1930 through to the mid-1980s. Coal tar enamel is a polymer based coating produced from the plasticization of coal tar pitch, coal, and distillates. CTE coatings were typically applied at approximately 465°F (241°C) on a prepared and primed pipe surface. Compared with synthetic polymers, CTE coatings have relatively low strength. Therefore, CTE coating systems were applied more thickly (typically 0.10 to 0.25 in.) than modern synthetic polymers, and incorporated inert fillers, along with inner and outer wraps of glass or mineral fiber to:

- Provide additional shear strength.
- Provide resistance to soil stress.
- Protect against rock damage during backfilling.
- Improve resistance to sag at elevated temperatures.

The coating was then typically finished with an outer layer of kraft paper or asbestos felt to provide mechanical support of the coating while it cooled, to provide protection of the underlying coating during handling and installation, and to prevent ultraviolet degradation of the enamel during storage in direct sunlight.

CTE coatings have generally had a very good performance history, particularly in relation to other vintage coating systems, displaying good adhesion, and provided they are installed correctly and operated within the known operating temperature limits of the coating system – up to 180°F (82°C), the coating generally shows a continuous, strong bond over time. CTE coatings show very low moisture absorption, are resistant to bacterial deterioration and soil chemicals, and cathodic disbondment. CTE coatings have high electrical resistivity; however, they do not shield protective CP currents as some other vintage coating systems do. Due to the high electrical resistivity, CP current demands are typically low.

With respect to limitations, apart from the aforementioned low mechanical strength, CTE coatings are vulnerable to ultraviolet degradation when exposed to direct sunlight for extended periods of time. In addition, CTE coatings represented a significant health hazard for workers during the hot application of the coating, which was associated with heavy generation of fumes.

According to the construction specifications for Line 5, CTE coating was hot-applied in a molten state, and reinforced with glass fiber. A final layer of asbestos felt outer wrap was then applied in a tight, uniform spiral. [37, pp. 34-35] Prior to the application of the coating, the pipe was mechanically cleaned and primed. Average coating thickness was 3/32 in., and ranged from a minimum thickness of 1/16 in. to a maximum thickness of 1/8 in.

Figure 2-2 depicts CTE-coated Straits Crossing line pipe welded in segments in preparation for installation. The asbestos felt outer-wrap is clearly visible in this photo, as are the fumes in the background, associated with coating operations.

Figure 2-2: CTE-Coated Straits Crossing Segments

2.4.1.1.1.3.1.2 Coating Condition

Enbridge conducts underwater inspections of the exterior of the Straits pipelines every two years, using remotely operated underwater vehicles and divers. The November 2014 *Underwater Inspection Report* prepared by Enbridge's contractor, Ballard Marine Construction, noted:

> *The exposed portions of the pipelines are heavily covered in zebra mussel growth, making a detailed analysis of the coating and actual pipe condition difficult. However a few instance [sic] of a small amount of coating delamination was observed.*

The report concluded, among other things, that "the pipeline currently appears to be in stable condition with minimal coating delamination". [38]

The proposed Consent Decree in United States vs. Enbridge Energy Limited Partnership, et al (W.D. Mich No 1:16-cv-914) requires Enbridge to, among other things, conduct a Biota Investigation:

> *Enbridge shall assess whether the accumulation of mussels and other biota have impacted the integrity of the pipelines' coating of the underlying metal, including areas where there are openings or "holidays" in the pipeline coating.*

In response to the State's *Request for Information*, dated March 29, 2017, which related to references to coating holidays and delamination in Enbridge's *Biota Work Plan*, Enbridge provided a *Supplement to Biota Work Plan*, in which the following points of clarification were provided:

- The Straits pipelines are protected by multiple layers of coating. These layers include a primer coat, a layer of enamel, and two layers (inner and outer) of glass fiber wrap. The portion of the coating system that protects against corrosion after installation of a pipeline is the enamel layer below the inner and outer wraps.
- The 18 areas originally subject to investigation included (i) areas where based on the visual inspection the outer wrap of the coating appears to have been dislodged; and (ii) areas where biota does not appear to be present on the pipe (but would normally be expected to be present).
- With respect to the areas where biota does not appear to be present, it is not clear at this time whether these locations reflect areas where the outer wrap of the coating is no longer in place or whether these locations reflect areas that simply are lacking biota.
- Ballard Marine Construction has conducted additional reviews of the 18 areas identified in the *Biota Plan* and has determined that there is no evidence of *bare metal* exposed on either pipeline in any of the areas.

Enbridge also provided responses to specific questions posed by the State. These responses included the following information:

- Of the 18 discrete locations that were identified in the Biota Work Plan document as being associated with coating damage, these areas ranged from 2-10 ft^2 per individual location, and totaling less than 100 ft^2. [39]
- Enbridge has seen no evidence that any of the areas identified in the Biota Work Plan should be classified as 'holidays', or areas of exposed bare metal. A CPCM

inline inspection was completed to measure local cathodic protection currents, and this inspection did not show any holidays. [40]

- Of the 18 identified areas, there are 8 where there is a lack of Biota, but no visible indication of anomalies to the coating and specifically to the outer wrap. In the remaining 10 identified areas, there is a lack of Biota and some indication of anomalies in the outer wrap. In all cases, all other layers of coating appear to be intact and unaffected, including the enamel layer that covers the pipeline. [41]
- There was one location (W-12A) among the 18 sites identified in the Biota Work Plan where the outer layer wrap was observed on the lake floor, and one location (E-02B) seen in the 2016 inspection where the outer layer wrap was observed on the coating floor. [42]
- The Cathodic Protection in-line inspection tool deployed on September 27, 2016, found that the coating was protecting the pipe at all locations including the 18 locations identified in the Biota Work Plan. [43]
- Enbridge has seen no confirmed locations of bare metal exposed at any point on the lines as shown by inline inspection results, including at the 18 locations identified in the Biota Work Plan. [44]
- The areas of "delamination" that have been observed exhibit only a lack of Biota – no visible indication of anomalies to the coating and specifically to the outer wrap. There are also a number of areas where there is a lack of Biota plus some indication of anomalies in the outer wrap. In all cases, all other layers of coating appear to be intact and unaffected. [45]
- When comparing the identified locations with past In-line Inspection data from corrosion tools, there is no external corrosion found at any of the 18 locations identified in the Biota Work Plan. [46]

In September of 2016, Enbridge commissioned Baker Hughes to inspect the West and East Straits crossing pipelines using its Cathodic Protection Current Mapping (CPCM) in-line inspection tool, and those pipelines were inspected on September 27 and September 28, 2016, respectively. The CPCM tool is the result of a technology development initiative that was jointly funded by Shell Global Solutions, Baker Hughes Pipeline Management Group and the U.S. Department of Transportation. The tool measures CP current direction and magnitude in the pipeline as a function of pipeline position. This enables measurements of current density to be made along the length of a pipeline, as well as the location and magnitude of current leaving or entering the pipeline, thereby permitting an assessment of stray current or interference, along with coating condition. The CPCM tool findings were:

1. No direct current sources were found along the length of the Straits pipelines, indicating that there were no sources of stray current or interference, and that CP currents were being obtained from rectifier beds outside of the Straits crossing segments.
2. Low levels of current density indicate that the coating is in excellent condition on both East and West pipelines.

Figure 2-3: Screen Capture from the 2012 Underwater Inspection

2.4.1.1.1.3.1.3 Cathodic Protection

CP is an electrochemical method used to prevent or control corrosion of buried or submerged metallic structures such as pipelines. CP systems are active systems which rely on the application of electric current to control corrosion by making the structure to be protected the cathode in an electrochemical cell. If current is interrupted, corrosion will progress at a normal rate for the material and environment. If supplied current is inadequate for complete protection, corrosion will progress at a reduced rate. After a CP system is installed and adjusted to provide adequate protection, currents and potentials should remain relatively stable; changes in currents or potentials usually indicate a problem. CP system performance is normally monitored by measuring the supplied current and by measuring the potential of the structure, relative a reference cell. Maintenance of CP systems may include inspection and adjustment of current rectifiers or anodes.

The Straits Crossing pipeline segments are protected by remote rectifiers located both north (5-1476, St. Ignace) and south (5-1480, Mackinaw) of the Straits. [47] A review of 580 monthly rectifier readings for these two rectifiers from January, 1995 through to March, 2017 indicated consistent performance, with only three brief outages at the St. Ignace and two brief outages at the Mackinaw rectifier stations over the time period. [47] A review of annual test lead survey readings for the Straits Crossing segments dating back to 1989 was completed, and no readings were found that did not meet protection criteria over this time period. [47] An interrupted close interval survey of the Straits

Crossing segments was completed in September 2003, and the potentials were found to meet the -850 'Off' criterion for 100% of the length of both the East and West segments. [48] The lack of recorded current anomalies in the CPCM survey conducted in September 2016 indicates that cathodic protection currents are continuing to be well maintained through the length of both crossing segments.

2.4.1.1.1.3.1.4 Corrosion Assessment and Monitoring

High-resolution magnetic flux leakage (MFL) in-line inspections of the East and West Straits Crossing pipelines has been completed every five years since 1998, with the most recent inspection being completed in 2013. High-resolution MFL identifies and measures volumetric metal loss occurring anywhere along the circumference of both the internal and external surfaces of the pipeline, including: [49]

- associated with girth welds and seam welds
- associated with dents
- situated beneath casings
- situated beneath repair clamps
- associated with manufacturing imperfections
- associated with gouges

In addition, it is capable of detecting the following:

- girth weld anomalies including circumferential cracks within girth welds
- dents
- manufacturing/mill type defects
- construction damage
- changes in nominal pipe wall thickness
- pipeline fixtures and fittings including:
    - tees
    - offtakes
    - valves
    - bends
    - anodes
    - buckle arrestors
    - external supports
    - ground anchors
    - repair shells
    - CP connections - ferro-magnetic type.
- ferrous metal objects in close proximity to the pipeline considered likely to affect the carrier

- protective coating or cathodic protection system
- casings, including eccentric casings where the degree of eccentricity is considered likely to affect the carrier protective coating or cathodic protection system
- reference marker magnets.

The detection, sizing and location accuracy of the tool employed during the 2013 inspection is summarized in the following table. [49]

Table 2-4: MFL Tool Performance Characteristics

Parameter	Metal Loss Category		
	Pitting <(3t x 3t)*	General (>3t x 3t)*	Gouging
Minimum depth for accurate sizing	If surface dimension is > 0.275" x 0.275" or 0.4t x 0.4t (whichever is greater): 0.2t	0.1t	If width > 0.5t or 0.275" (whichever is greater): 0.2t If width >3t: 0.1t
Sizing accuracy (depth)	±0.1t	±0.1t	±0.1t
Sizing accuracy (length)	±0.4"	±0.8"	±0.8"
Sizing accuracy (width)	±0.8"	±0.8"	±0.8"
Location accuracy (axial)	±0.8" between the feature and the reference girth weld and ±1% of stated distance between reference girth weld and identified location reference		
Location accuracy (circumferential)	± 7.5 degrees, which for ease of reference is stated to the nearest half hour clock position		
Notes: t = nominal wall thickness * Metal loss is characterized by the minimum rectangle of dimensions, circumferential width (W) and axial length (L) that contains the surface area of pipe affected by metal loss			

It can be difficult to achieve the normal sizing accuracy for mill/manufacturing faults depending on whether these metal loss features are the result of hot working or cold working of the pipe steel. Consequently, the sizing accuracy specified for corrosion in Table 2-4 may not be applicable to mill/manufacturing faults.

A review of the features list associated with the most recent (2013) MFL inspection was undertaken. Of all past inspections, this most recent inspection is most representative of the current metal-loss condition of the pipeline, and was completed using the most current technology.

East Segment

Along the East pipeline, the following feature types were identified:

- bends
- girth welds
- metal loss features (internal)
- mill fault features
- offtakes

- supports
- valves

Of the above features, only metal loss features and mill fault features are considered potential defects; the rest are normal features that are part of the design of the pipeline installation.

While internal metal loss features (see Section 2.4.1.1.1.3.2) were detected, no external metal loss features were discovered.

Thirty-five features were identified as mill fault features; 13 of these were associated with the external surface, and 22 with the internal surface of the pipeline (see Section 2.4.1.1.1.3.2). The distribution of the external mill fault features was quite dispersed and random in both location and orientation about the circumference of the pipe. This type of distribution is typical of manufacturing type anomalies, and particular, of seamless pipe, which is known to be associated with non-uniform variation in wall thickness caused by the pipe manufacturing process. Unless otherwise noted, such features are normally considered to be benign, inactive features that would have been subjected to the pre-commissioning hydrostatic test.

A study, completed by Lamontagne Pipeline Assessment on behalf of Oak Ridge National Laboratory and the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("The US DOT Straits ILI Review") undertook to evaluate the mill fault features to establish whether they were showing any evidence of growth over time. This was undertaken by analyzing the growth of matched external metal loss anomalies between the 2008 MFL and 2013 MFL inspections. All variances in depth were found to be within the ±10% error of the tool. Therefore considering tool error there is no growth as would be expected if these are all manufacturing anomalies. [50]

West Segment

Along the West pipeline, the following feature types were identified (no metal loss features were identified):

- bends
- girth welds
- mill fault features
- offtakes
- valves.

Of the above features, only mill fault features are considered potential defects; the rest are normal features that are part of the design of the pipeline installation.

Sixty-five features were identified as mill fault features; 25 of these were associated with the external surface, and 40 with the internal surface of the pipeline (see Section 2.4.1.1.1.3.2). As was the case with the East Segment, the distribution of the external mill fault features was quite dispersed and random in both location and orientation about the circumference of the pipe, typical of manufacturing type anomalies, and particular, of seamless pipe, which is known to be associated with non-uniform variation in wall thickness caused by the pipe manufacturing process. Unless otherwise noted, such features are normally considered to be benign, inactive features that would have been subjected to the pre-commissioning hydrostatic test.

The US DOT Straits ILI Review found in a comparison of matched external mill fault features between the 2008 MFL inspection and the 2013 MFL inspection that all variances in depth were found to be within the ±10% error of the tool. Therefore considering tool error there is no growth as would be expected if these are all manufacturing anomalies.

2.4.1.1.1.3.1.5 Operating Experience

External corrosion is not a common cause of failure in offshore transmission pipelines. In 2008, the U.S. DOT Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety commissioned a study to provide a high-level common understanding of issues related to pipeline corrosion. [51, p. 15] With respect to the operating experience of offshore pipelines, the report concluded:

> *While not a focus of this study, it is important to contrast the issue of external corrosion in onshore buried pipelines with external corrosion of offshore pipelines. Although salt water is much more corrosive than most soil environments, cases of significant external corrosion on offshore pipelines are extremely rare. The ability to control external corrosion has been mastered to a high degree, as compared to onshore performance. This is particularly due to the homogeneity of the offshore environment, and the predictability of coating and cathodic protection. The offshore environment is very uniform in composition and of high conductivity, thus enabling the uniform and consequently effective application cathodic protection. Furthermore, the alkaline environment produced by the cathodic protection causes calcareous deposits (primarily magnesium carbonate) to precipitate at the coating holidays (holes), essentially plugging the holidays and separating the steel from the water.*

Failures that do occur on offshore pipelines occur predominately on the riser as a result of corrosion. The consistent wetting and drying in the splash zone combined with defects in the coatings are the usual contributors to the problem. Risers will fail often, but the failure is rarely catastrophic and downtime is usually minimal as compared with onshore pipeline failures due to corrosion[10].

2.4.1.1.1.3.2 Internal Corrosion

A summary of the threat attribute review and assessment for the threat of internal corrosion as it relates to the Straits crossing pipelines is provided below.

2.4.1.1.1.3.2.1 Product Stream Characteristics

Under normal operations, liquids pipelines with low levels of basic sediment and water (BS&W, 0.25-0.5%), and which operate at high enough throughput levels to main turbulent flow, are not highly vulnerable to internal corrosion. [52]

Turbulent flow controls solids deposition, and maintains what little water exists entrained in the product stream. The product stream, in conjunction with the operating and flow

[10] Note that risers are a feature of offshore platforms. No risers exist on the Enbridge Line 5 pipeline.

characteristics should render the pipe wall in an oil-wet (i.e. non-corrosive) condition. At low BS&W levels, in conjunction with turbulent flow, water will remain entrained in oil.

A Reynolds Number (Re) analysis was conducted to determine the flow conditions (turbulent vs. laminar flow) in the Straits pipeline.

The Re is a dimensionless quantity in fluid mechanics used to help predict flow patterns in different fluid flow situations. It has wide applications, and is used to predict the transition from laminar to turbulent flow.

For flow in a pipe or tube, the Re is defined using Equation 2-1.

$$\mathrm{Re} = 7{,}745.8 \text{ x } \frac{\mathrm{Q} \text{ x } D_H}{\nu \text{ x } \mathrm{A}}$$

Equation 2-1: Reynolds Number Calculation

Where:

D_H = Hydraulic diameter (ID) of the pipe (in.)
Q = Volumetric flow rate (ft^3/s)
A = Pipe cross-sectional area (ft^2)
v = Kinematic Viscosity (cSt)

The calculation was performed using the following parameters:

Table 2-5: Hydraulic Variables – 20-in. Straits Crossing Segments

Variable	Units	Value	Notes
Pipe diameter	in.	20	20-in. pipe
Wall thickness	in.	0.812	Conventional crossing specific
Hydraulic diameter (DH)	in.	18.38	Pipe ID
Flow area (A)	ft^2 (m^2)	4.39 (0.408)	
Flow rate	bbl/d	270,000	For each pipeline
Flow rate (Q)	ft^3/s (m^3/s)	63,164 (1,789)	
Kinematic Viscosity (v)	Highest batch product kinematic viscosity at 52°F (10°C) based on information provided by Enbridge.		

Note that the highest viscosity of the batched fluids was used to determine the lowest Re, which is a conservative assumption.

Using these parameters yields the Re result of approximately 9,000. Flow in a pipeline can be considered fully turbulent at Reynolds numbers greater than 4,000. Reynolds numbers in the range of 2,000 to 4,000 indicate transitional flow from laminar to turbulent, and numbers less than 2,000 are fully laminar.

Consequently, the flow through the Straits Crossing pipelines fall fully within the turbulent range.

Enbridge's tariff specifications for Line 5 limit BS&W to less than 0.5%. [30] At this level, the turbulent flow causes the small amounts of water and solids that would be present to be fully-entrained within the product stream, causing the pipe wall to be oil wet, which constitutes a non-corrosive condition.

In addition to considering regular operating conditions, a full evaluation of operational factors must also take into consideration the frequency with which extended shutdowns are incurred on a system. Even though free water might readily be entrained within a turbulent flow, rendering the inside of the pipe in an oil-wet, non-corrosive condition, extended periods of operational shutdown can result in stratification and settling out of any free water that might be present in the product stream. Should these extended shutdown periods occur frequently enough, the accumulated amount of time that water has settled out, and has come into contact with the inside surface of the bottom of the pipe can be significant enough to result in corrosion, even in pipelines that have relatively small amounts of free water. Nevertheless, a review of historical operations indicates that the Straits Crossing segments over the course of the past 10 years operate 99.18% of the time. [53] Along Line 5, Enbridge has incurred only three outages that either equaled or exceeded 48 hours in the last 10 years, itemized as follows: [54]

- July 21, 2012 - Duration of 67 hours (Planned)
- January 23, 2013 - Duration of 53 hours (Planned)
- April 23, 2014 - Duration of 87 hours (Planned).

While the accumulated 207 hours of outage in the past 10 years is not considered highly significant from the perspective of creating a corrosive environment, the degree to which outages such as the above might or might not have caused corrosion should be evident from a review of the 2013 MFL data. The 2013 MFL inspection will be representative of all but 87 of those 207 hours of outage. The next section contains an evaluation of the 2013 MFL inspection data.

2.4.1.1.1.3.2.2 Corrosion Assessment and Monitoring

Although product characteristics and flow conditions may act to entrain water and solids within the product stream, rendering the pipe wall in an oil-wet condition, monitoring and the implementation of appropriate mitigation strategies, where warranted, is required to ensure that internal corrosion is not occurring. Two monitoring strategies are the use of internal coupons and in-line inspection for wall loss.

As indicated in the discussion under *External Corrosion*, high-resolution MFL in-line inspections of the East and West Straits crossing pipelines have been completed every five years since 1998, with the most recent inspection being completed in 2013. A review of the features list associated with the most recent (2013) MFL inspection (which is most representative of the current condition of the Straits pipelines) was undertaken. A discussion of the findings related to internal features associated with that inspection is provided below, for the East and West pipeline segments.

Internal Features Associated with 2013 MFL Inspection (East Segment)

Along the East segment, nine metal loss features were identified along the East segment – all of which were located on the internal surface, and located within the first 19 ft. (6 m) of the inspection run (apparently within the launcher assembly), in 0.500-in. wall thickness pipe upstream of the mainline valve. As such, none of these features were technically located within the Straits Crossing segment, defined as the 0.812-in. wall thickness pipe that constitutes the portion of pipeline between isolating mainline valves. Regardless, because of the location of the metal loss features within the launcher assembly, these features cannot be considered to be associated with active, ongoing internal corrosion attributable to corrosive products, but rather, it is more likely that these features are associated with the ingress of water during launching operations.

Twenty-two features were identified as internal mill fault features. The distribution of the internal mill fault features was quite dispersed and random in both location and orientation about the circumference of the pipe. This type of distribution is typical of manufacturing type anomalies, and particular, of seamless pipe, which is known to be associated with non-uniform variation in wall thickness caused by the pipe manufacturing process. Conversely, internal corrosion tends to be preferentially-oriented at the bottom of the pipe. Unless otherwise noted, manufacturing anomalies are normally considered to be benign, inactive features that would have been subjected to the pre-commissioning hydrostatic test.

The US DOT Straits ILI Review found in a comparison of matched internal mill fault features between the 2008 MFL inspection and the 2013 MFL inspection that all variances in depth were found to be within the ±10% error of the tool. Therefore considering tool error there is no growth as would be expected if these are all manufacturing anomalies.

Internal Features Associated with 2013 MFL Inspection (West Segment)

Along the West segment, no internal metal loss features were found, however 40 internal mill fault features were identified. As was the case with the East Segment, the distribution of the internal mill fault features was quite dispersed and random in both location and orientation about the circumference of the pipe, typical of manufacturing type anomalies, and particular, of seamless pipe, which is known to be associated with non-uniform variation in wall thickness caused by the pipe manufacturing process. Unless otherwise noted, such features are normally considered to be benign, inactive features that would have been subjected to the pre-commissioning hydrostatic test.

The US DOT Straits ILI Review found in a comparison of matched internal mill fault features between the 2008 MFL inspection and the 2013 MFL inspection that all variances in depth were found to be within the ±10% error of the tool. Therefore considering tool error there is no growth as would be expected if these are all manufacturing anomalies.

Corrosion Coupons and Probes

Outside of in-line inspection, corrosion coupons or electrical probes – primarily electrical resistance (ER) probes – are the two most common methods for detecting corrosion. Corrosion coupons consist of a piece of material of the same type as the pipeline that is being monitored, that are installed in the pipeline at locations known to be potentially vulnerable to corrosion (i.e., potential water accumulation and hold-up points). Prior to installation, coupons are accurately weighed. They can then be removed from the pipeline at intermittent periods and re-weighed to determine if they have lost weight. This information can be used to determine corrosion rate, extent, distribution of localized corrosion, and the nature of corrosion.

Like coupons, electrical resistance probes are installed in a pipeline at locations of potential water accumulation and hold-up, and are made of materials that are representative of the pipeline material. They work on the principal that electrical resistance is inversely proportional to cross-sectional area. This enables the electrical resistance in an electrical resistance probe to be continuously monitored to provide metal loss/corrosion rate measurements and episodes of higher corrosion rates in an online and continuous manner.

Enbridge does not have coupons installed in the vicinity of the Straits Crossing segments, however this information, had it been available, would not be as valuable, or indicative of the potential for internal corrosion within the Straits Crossing segments as the high-resolution MFL data, which is available.

2.4.1.1.1.3.2.3 Receipt Points

Receipt points (i.e., the locations that a pipeline takes receipt of products) matter in the context of operating experience downstream of those receipt points, and also in the context of how much control is imposed on the receipt of off-specification products. A receipt point located immediately upstream of a segment of interest may play a considerable role in the vulnerability of that segment to internal corrosion despite the operating experience of segments that are located further upstream of that receipt point. This may be particularly true if off-specification products have been historically delivered to the pipeline at that receipt point.

Line 5 takes receipt of products at two locations upstream of the Straits: at Superior, WI (the start of the pipeline) and at Rapid River, MI, located about 125 mi. (200 km) upstream of the Straits.

2.4.1.1.1.3.2.4 Mitigation Programs

For pipelines that are vulnerable to internal corrosion, two types of mitigation programs are used by operators to manage and mitigate that vulnerability: inhibition and cleaning pigging. These two strategies are often employed together, with cleaning pigging being undertaken to remove paraffin deposits, apply corrosion inhibitors, clean deposits from the line, and keep out accumulations of water where bacteria grow and corrosion occurs. Chemical treatment (either as a batched product, or in the form of continuous injection) may be used, as applicable, to treat corrosive product streams by acting as sour point depressants, flow improvers, corrosion inhibitors, biocides and hydrate prevention.

Enbridge does not employ chemical injection or cleaning programs on the Straits Crossing segments. [55]

2.4.1.1.1.3.3 Selective Seam Corrosion

Selective seam corrosion, also called preferential seam corrosion, is metal loss caused by either internal or external corrosion along the seam area of a pipe. Where selective seam corrosion is a problem, it is because corrosive attack is occurring along the pipe seam bond line at a higher rate than in the pipe body, resulting in a V-shaped crevice or groove within the bond line.

Because the line pipe used in the 20-in. Straits crossing segments is seamless, this threat is not applicable to those segments.

2.4.1.1.1.3.4 Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a form of environmentally assisted cracking, wherein small surface cracks can form and grow over time. Other forms of environmental cracking, such as sulfide stress cracking (SSC), occur only in sour (H_2S-bearing) environments. H_2S in liquid is a quality parameter that is measured and monitored on Enbridge transport commodities. This monitoring ensures that Line 5 does not transport sour products, [56] and is therefore not vulnerable to sour service cracking mechanisms.

In SCC, multiple small individual cracks will typically form adjacent to one another in an array. If the cracks continue to grow, they frequently overlap and/or coalesce such that they become the equivalent of a large single crack in terms of their effect on the pressure carrying capacity of the pipe. Eventually such overlapping and coalescence can create a crack large enough to cause the pipeline to leak or rupture.

Two forms of SCC have been observed in carbon steel transmission pipelines; “high pH SCC”, and “near-neutral pH SCC”, with the “pH” referring to the environment on the pipe surface at the crack location. [57, p. 25][11]. High pH SCC is characterized by tight cracking that proceeds along steel grain boundaries (inter-granular cracking), and tends to form within a narrow cathodic potential range and at a local pH over 9. Near-neutral pH SCC is characterized by wide, corroded, transgranular attack at a local pH of 5.5 to 7.5, and is associated with mild concentrations of CO_2 in groundwater.

Regardless of the form of SCC, three conditions must be present for SCC to occur: a susceptible material, a conducive environment, and a tensile stress. [35, p. 74]

1. *Material*—All commonly used line pipe steels are susceptible, though susceptibility may vary considerably from one material to another.
2. *Environment*—Specific forms of SCC are associated with specific terrain and soil types, particularly those having alternating wet-dry conditions and those that tend to damage or disbond coatings. However, SCC can occur in almost any soil type since the local electrochemistry at the pipe surface may be isolated from the surrounding conditions. Thus pipe coating type and condition can be an important factor.
3. *Stress Level*—Susceptibility to SCC increases with stress level, and pipelines that are operated at stress levels above 60 % of SMYS appear to be the most susceptible. There is thought to be a lower-bound threshold stress level below which SCC will not occur, but the threshold has not been firmly established and is likely to be situation dependent. SCC has been identified in one case in a pipeline being operated at hoop stress level of 47 % of SMYS. Conducive stress levels may occur at local structural discontinuities (e.g. weld toes) or sites of deformation due to outside forces (e.g. rock dents). Some amount of stress cycling can promote SCC growth by breaking the oxide film that forms on the crack surface, re-exposing the crack tip to the environment. Cyclic loading seems to be an important factor in the initiation of SCC.

Beyond the above, each form of SCC has its own susceptibility factors, with high pH SCC being associated with higher operating temperatures – typically above 100°F (38°C), and near-neutral pH SCC being more commonly associated with coatings that shield CP current (polyethylene tape coatings).

A review of failure incidents reported in the U.S. DOT Pipeline and Hazardous Materials Safety Administration’s Hazardous Liquid Pipeline Systems Incident Database (2010 to December 2016) indicated that whereas the broad category of *environmental cracking*

[11] pH is the measure of the relative acidity or alkalinity of water. It is defined as the negative log (base 10) of the hydrogen ion concentration. Water with a pH of 7 is neutral; lower pH levels indicate an increasing acidity, while pH levels above 7 indicate increasingly basic solutions.

(under which SCC falls) accounted for 2.3% of all failure incidents in onshore pipelines, there were no failure incidents attributed to this cause in offshore pipeline infrastructure.

The relevance of the above susceptibility factors in respect of the attributes of the Line 5 20-in. Straits Crossing pipelines are summarized in the next sections.

2.4.1.1.1.3.4.1 Environment

The Line 5 20-in. Straits crossing segment is principally an offshore segment. Neither the near-neutral pH, nor the high pH form of SCC has been associated with offshore pipeline infrastructure. [51, p. 27]

2.4.1.1.1.3.4.2 Coating

Whereas much attention has been paid to potential coating holidays in the CTE coating on the 20-in. Straits pipelines, the collective evidence (summarized in Section 2.4.1.1.1.3.1) suggests that the coating is consistently well-bonded to the steel line pipe. This is due to:

- No evidence of any external corrosion features on the most recent (2013) MFL feature lists for the East and West Straits segments.
- The September, 2016 CPCM surveys of the East and West Straits Segments had the unique ability to assess coating condition and coating holidays. The results of those surveys indicated "Based on the amount of DC current and the DC current density on the line it appears the line has an excellent coating system" [58, p. 4] [59, p. 4].
- CTE coating does not shield the pipeline from CP. While this does not preclude the possible formation of SCC, it does go a long way towards addressing one of the most significant vulnerability factors associated with near-neutral pH SCC, for which operating experience dictates is primarily associated with shielded conditions.

2.4.1.1.1.3.4.3 Operating Stress Level

The maximum operating pressure of 600 psi represents a stress level that is low (21% of specified minimum yield strength), relative to stress levels that have been associated with pipelines on which SCC has been experienced (typically above 60% of specified minimum yield strength).

2.4.1.1.1.3.4.4 Operating Temperature

One year's worth of twice-daily temperature records for the North Straits location were reviewed, and temperatures were found to range between 43.2°F and 83.5°F, with an average temperature of 57.6°F. [60] These temperatures are well below those that are associated with high pH SCC – typically >100°F (38°C).

2.4.1.1.1.3.5 Manufacturing Defects

According to the threat attribute discussion contained in API 1160 – Managing System Integrity for Hazardous Liquid Pipelines, pipeline failures associated with the threat category of Manufacturing Defects is principally associated with defective pipe seams and defective pipe body. [35, pp. 75-76]

Defective pipe seams relate to pipe materials made with welded longitudinal or helical seams, which may contain defects within the seam weld or the heat-affected zones. This class of manufacturing defect does not apply to seamless pipe, such as was used in the 20-in. Line 5 Straits Crossing segments.

Pipe body defects include those that have been directly associated with pipeline failures, such as hard spots, cracks, and laminations, as well as surface imperfections, such as pits, scabs, and slivers, which, although not normally structurally significant to the pipe's ability to contain pressure, can adversely affect coating integrity.

The manufacturing process for the production of seamless pipe is distinct from welded pipe formed from hot rolled plate. Accordingly, seamless pipe is associated with manufacturing defects that are specific to that process. [61, p. E8] Seamless pipe begins as a billet (typically a solid round of steel) that is heated to forging temperatures before being pierced with a mandrel and rolled to produce the desired diameter and wall thickness. The seamless pipe manufacturing process is inherently sensitive to the ability to achieve a uniform forging temperature prior to piercing, and variations in temperature can result in greater variations in wall thickness. Accordingly, the magnitudes of wall thickness variations in seamless pipe tend to be greater than those associated with welded steel pipe. In general, while these wall thickness variations may be identified as manufacturing anomalies in in-line inspection logs, they have no significant effect on pipeline integrity.

Other anomalies that have occurred in seamless pipe include surface imperfections, such as scabs, blisters, slivers, seams, laps, pits, roll-ins, hot tears, and plug scores. Laminations represent another manufacturing defect associated with the manufacture of seamless pipe, and can result from imperfections in the billet caused by insufficient ingot cropping.

Numerous features of the type enumerated above were noted in the inspection logs of the 2014 tethered PipeScan / WeldScan automated inspection performed by Oceaneering, which identified numerous areas of local and scattered wall thinning due to manufacturing processes, slivers, and laminations. The 2013 MFL inspections of the East and West Straits crossing segments identified numerous areas of wall loss attributed to manufacturing anomalies, with approximately 10% of the pipe joints on the East Segment having wall loss anomalies, and approximately 17% of the pipe joints on the West Segment having wall loss anomalies.

As discussed in Section 2.4.1.1.1.3.1, a study, completed by Lamontagne Pipeline Assessment on behalf of Oak Ridge National Laboratory and the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) undertook to evaluate the mill fault features to establish whether they were showing any evidence of growth over time. This was undertaken by analyzing the growth of matched external metal loss anomalies between the 2008 MFL and 2013 MFL inspections. All variances in depth were found to be within the ±10% error of the tool. Therefore considering tool error there is no growth; this is consistent with these features being manufacturing anomalies.

Regardless of the manufacturing process, any pre-existing anomalies that are not found by means of the pipe manufacturer's hydrostatic test and/or non-destructive examinations and are not eliminated by the initial preservice hydrostatic test of the pipeline, will remain as anomalies in the pipeline. Frequently, such anomalies are revealed by in-line inspection or hydrostatic retests. Having survived an initial preservice hydrostatic test to a level of at least 1.25 times MOP, these types of anomalies will be non-injurious to pipeline integrity unless they are subject to enlargement by pressure-cycle induced fatigue.

Vulnerability factors associated with failures caused by manufacturing defects include: [62, p. 93]

- The presence of pressure-cycle induced fatigue,
- Operation at operating stress levels in excess of 30% of specified minimum yield strength, and
- The absence of a pre-commissioning hydrostatic test to a pressure of at least 125% of maximum operating pressure.

The relevance of the above susceptibility factors with respect to the attributes of the Line 5 20-in. Straits Crossing pipelines are summarized in the next section.

2.4.1.1.1.3.5.1 Pressure-Cycle Induced Fatigue

Pressure-cycle-induced fatigue might play a role in growing sub-critical defects associated with other threats to failure. Otherwise, sub-critical defects that do not experience growth in service are considered to be stable defects that have a factor of safety established through post-installation hydrostatic testing.

The degree to which fatigue can contribute to the growth of sub-critical defects is a function of the magnitude and frequency of individual pressure cycles that exist within the operating pressure spectrum of a pipeline. Pressure-cycle induced fatigue is discussed in detail in Section 2.4.1.1.1.3.12. That discussion describes an analysis of the pressure spectra associated with the operating conditions of the Straits Crossing pipelines. That analysis was completed to assess the pressure-cycling severity on that pipeline segment, and the potential for operating pressure cycling to contribute to the growth of sub-critical defects by means of fatigue mechanisms. That analysis found that the pressure profile for the Straits Crossing segments is classified as *Light*, meaning that the operating pressure spectrum that is characteristic of the Straits Crossing is not associated with pipelines that would experience failures due to activation of sub-critical defects by pressure-induced fatigue.

2.4.1.1.1.3.5.2 Operating Stress Level

A MOP of 600 psi (4,136 kPa) represents a stress level that is 21% of specified minimum yield strength (SMYS), which is low relative to stress levels that have been associated with enhanced vulnerability to manufacturing defect failure.

2.4.1.1.1.3.5.3 Hydrostatic Testing

Construction records show that the East and West Straits pipelines underwent an installation hydrostatic test (prior to lowering, while floating on pontoons) to 1,200 psi. for 5 hours. The pipelines then underwent a post-Installation test to 790 psi for 4 hours (West Segment) and 12 hours (East Segment). [32] These test pressures represent test pressure to operating pressure ratios of 2.0 and 1.32, respectively, which are both higher than the 1.25 test pressure ratio cited as providing protection against failure due to manufacturing defects.

Enbridge plans to test both the East and West Straits pipelines to a minimum test pressure of 1,200 psi in or around June of 2017. [63] Should these tests be successfully completed, they will provide a factor of safety factor of 2.0 with respect to any defects that may be present in the pipeline segments.

2.4.1.1.1.3.6 Construction and Fabrication Defects

According to the threat attribute discussion contained in API 1160 – Managing System Integrity for Hazardous Liquid Pipelines, pipeline failures associated with the threat category of Construction and Fabrication Defects is principally associated with the following types of defects:

- defects in girth welds and welds of fabricated fittings or branch connections
- installation damage, such as rock dents,
- bending mandrel marks, ripples, buckles and wrinkle bends[12].

2.4.1.1.1.3.6.1 Defects in Girth Welds and Fabricated Fittings / Branch Connections

The imposition of quality control measures, such as the adherence to qualified welding procedures, the qualification of welders, and the use of non-destructive inspection techniques for weld examination helps to prevent the occurrence of large, structurally-significant girth weld defects. A review of construction reports for the Straits of Mackinac indicated that welders were qualified to weld on the heavy-wall (0.812″ wall thickness) Straits crossing segments [64, p. 19] [65, pp. 29-30], and that all welds on the Straits crossing were x-rayed. [66] Pictorial documentation indicates that welds were also visually inspected. A welding procedure was used to qualify welders and for production welding. [67, p. 25] Although this procedure does not specify the type or number of essential variables that are commonly detailed in modern welding procedures, it does provide limits on geometric tolerances, such as welding process to be used, joint preparation and fit-up, details requirements for the types of consumables to used, provides requirements for preheating, welding progression, inspection and repairs. In that respect, the welding procedure provided some basis for process control. The welding procedure was augmented by specifications contained in the construction specification, which detailed additional requirements on welding process, fit-up, pre-heat and inter-pass temperature control, and welder qualification. [65, pp. 29-30] Additionally, this specification established limitations for the following welding defect classes:

- burn-through
- lack of penetration
- undercut
- misalignment
- slag
- reinforcement
- pinholes.

[12] Wrinkle bends are associated with vintage construction practices prior to 1952, and which were in declining use through the 1940s (Integrity Characteristics of Vintage Pipelines, 2005).

Aside from acetylene girth welds (a joining practice that was used in pipeline construction up until approximately 1940) [61, p. 27], pipeline failures resulting from girth weld defects as the primary cause of failure are rare. [35, p. 76] Because girth weld defects lie in the plane of principal operating stresses, some form of extreme external loading is generally required for them to play a role in pipeline failure. This form of external loading is addressed in Section 2.4.1.1.1.3.11.

Flaws in fabricated fittings and branch connections can occur, and these failures are often related to the presence of geometric features that can act to concentrate stresses, the presence of hydrogen (which can act to embrittle the weld region), and the presence of bending moments. In addition, pipeline failures have been attributed to the use of certain pipeline repair fittings or practices, such as some designs of pipe sleeve or repair welding techniques. The presence of such features is readily detected through in-line inspection.

Figure 2-4: Shielded Metal Arc Welding of Straits Pipe Segment

Figure 2-5: Visual Inspection of Girth Weld on Straits Pipe Segment

Review of In-Line Inspection Results Related to Welding Defects

A review was completed of the 2014 UCc Ultrasonic Crack Detection Inspection of the East and West Straits Crossing (NDT Global). An amplitude threshold criterion of 49 dB was used in this inspection for the purpose of establishing reporting criteria against circumferentially-oriented features that were assessed as being *crack-like*.

Fourteen features in the East Leg, and 21 features in the West Leg were identified that exceeded the above reporting threshold.

In the East Leg, 12 features had estimated peak feature depths less than 0.039″ deep, one had a peak feature depth that was estimated to be 0.043″ deep, and one had a peak feature depth that was estimated to be 0.051″ deep.

In the West Leg, 25 features had estimated peak feature depths less than 0.039″ deep, and one had an estimated peak feature depth that was estimated to be 0.039″ deep.

No crack-like anomalies were associated with any of the fitting or branch connection locations, and no repair sleeves were identified within either of the two crossing segments.

With respect to the 2014 UCc Ultrasonic Crack Detection Inspection of the East and West Straits Crossing segments, Enbridge reports that on the East Straits, all features identified as “crack related” were in the base pipe metal and not at girth welds. Thus these aren’t believed to be caused or stemming from the welding process between two joints. On the West Straits, all but one “crack related” feature were reported in the base pipe metal. Visual inspection was conducted to validate the inspection results and no cracking was identified. There was a superficial mill scab, not injurious to the integrity of the pipe that was identified on the East pipeline, and some minor tool markings that were created due to handling during installation of the West pipeline. The remaining reported “crack related” features are believed to be manufacturing related, not requiring repair. Based on all field inspections of reported features, no injurious cracks have been observed in either of the Straits pipelines. [68]

The UCc tool is planned for re-inspection in Q2 2017.

The 2014 tethered PipeScan / WeldScan automated inspection performed by Oceaneering used time of flight diffraction (TOFD) and phased array (PA) pulse-echo ultrasonic techniques to detect and size surface breaking and volumetric discontinuities in pipeline girth weld and the girth weld heat-affected zone areas.

The reporting thresholds for this inspection were based on ultrasonic amplitude thresholds, expressed as % full-screen height (FSH), as follows:

- crack-like surface-breaking / subsurface features ≥20% FSH and ≥25 mm in length
- planar surface-breaking features ≥40% FSH and ≥ 25 mm in length
- planar sub-surface features ≥40% FSH and ≥25 mm in length
- volumetric surface-breaking features ≥40% FSH and ≥25 mm in length
- volumetric sub-surface features ≥40% FSH and ≥25 mm in length
- combined planar / volumetric surface-breaking features ≥40% FSH and ≥ 25 mm in length
- combined planar / volumetric sub-surface features ≥40% FSH and ≥25 mm in length
- geometric features ≥40% FSH if extent appears to obscure potential surface crack-like features.

In the February 06, 2016 tethered *PipeScan / WeldScan Inspection Report for the West Straits Crossing*, it was noted that the girth welds displayed significant amounts of porosity, slag and lack-of-fusion, typical of vintage manual welding. There were two indications that exceeded the above reporting thresholds:

- Feature # IND00000: Slag / LOF open to root
- Feature # 044: Planar volumetric indication.

In addition, at GW ID 340, an area of >0.126 in. (3.2 mm) misalignment was noted, but was not scanned to prevent transducer damage.

In reply to questions pertaining to these features, Enbridge responded: [69]

> *Feature #IND00000 & Feature #044: The 2013 MFL tool called a 27% deep internal manufacturing defect on this joint. However, this indication was reported in the base metal and is not associated with the girth weld. The tethered report did not provide a relative distance on the joint for Feature #044 so it is unknown if it aligns directly with the manufacturing defect called by the 2013 MFL tool. IND00000 and Feature #044 are likely manufacturing anomalies created from the seamless pipe manufacturing process that were deemed acceptable at the time of production and remain non-injurious to the pipeline. Additionally, seamless pipe manufacturing can create variations in pipe wall thickness that can be misconstrued as defects by ultrasonic wall measurement ILI tools. MFL inline inspections are planned for 2017 on both Straits pipelines to monitor the condition of the pipeline.*
>
> *GW ID 340: No misalignment or wall thickness changes were detected on this girth weld in the 2016 or 2013 Geopig data. From the 2013 and 2016 Geopig raw data there appears to be a larger sensor bounce over this girth weld than the adjacent girth welds; this is likely a result of unsmooth surface near the girth weld.*

In the February 09, 2015 tethered *PipeScan / WeldScan Inspection Report for the East Straits Crossing*, it was noted that the girth welds displayed significant amounts of porosity, slag and lack-of-fusion, typical of vintage manual welding. There were no indications that exceeded the above reporting thresholds.

No anomalies were associated with any of the fitting or branch connection locations, and no repair sleeves were identified within either of the two crossing segments.

2.4.1.1.1.3.6.2 Installation Damage

While mechanical damage created during the installation of a pipeline such as rock dents, wrinkle bends, and buckles has been associated with pipeline failures, such damage is readily detected through in-line inspection. Ripples and bending mandrel marks are considered non-injurious to pipeline integrity [35, p. 76], although these features are also readily detected through in-line inspection.

A review and analysis of information, including the reports and inspection logs, was completed of the 2013 and 2016 Geopig inspections performed by Baker Hughes, with findings summarized in the next section.

2013 Geopig Inspection (Baker Hughes)

A review of the 2013 Baker Hughes *Geopig Inspection Report* was completed. The reporting thresholds for that inspection were:

- geometric anomalies >2% nominal OD
- ovalities >5% nominal OD
- outward wrinkles >1% nominal OD
- dents >1% nominal OD that meet the criteria of *dents in close proximity*, or that contain multiple apexes

- areas with either vertical or horizontal bending strain difference exceeding 0.1% with pipeline movement and spanning more than one pipe joint.

In the East Straits Crossing segment, one feature was found that exceeded the reporting threshold. This was a dent with multiple apexes, having a maximum depth of 1.49% nominal OD. On February 26, 2016, Enbridge submitted a response [70] to the following PHMSA Information Request:

> *Further information is required on a dent delineated in the 2013 BH Geopig Inspection in GW 6520 (16,300.169 ft.). Documents "PI-Planning-0001-031014D" and "L5 (20in) ENO-EMA 2013 Geopig BH Issue 1 - PI Listing'', describe the issue.*
>
> *What was discovered upon further review and visual inspection?*
>
> *Is there a more updated PI-Planning version?*

The response indicated that the 2013 East Straits Geopig inspection reported a dent downstream of GW 6520 denoted as DNT 1, having a depth of 1.49% of pipe OD, and characterized as *multiple dents*. Analysis determined that the dent had been formerly identified as a 0.6% OD unreported feature in the 2008 GE caliper inspection, and that the feature did not correspond to a pipe support (anchor) location. As part of the 2014 span remediation project, Enbridge conducted an inspection of the DNT 1 feature using divers. The divers were instructed to conduct visual observations of the dent, note any observed gouging or other damage, and place a straight edge along the pipeline in the area of the ILI call to allow for measurement of depth sizing.

The results from the divers' visual inspection revealed that there was some minor coating damage located near the ILI-reported location and there were some markings on the pipe from the banding used during installation of the pipe. It was also determined, however, that there was no corrosion observed within the coating damage area, and there was no denting, gouging, or scratching identified in the vicinity of the DNT 1 location. As there was no measurable deformation, it was determined that the DNT 1 feature was acceptable, and no repair was required.

As part of the analysis completed, both the East and West Straits Crossing segments were evaluated for pipeline movements between the current inspection and the 2003 geopig inspection. Apart from the launcher and receiver locations (where replacements had been completed), no differential bending strain exceeding the evaluation threshold of 0.1% were found on either the East or West Straits Crossing segments.

The analysis of inertial data identified 20 bends on the East Crossing and 23 bends on the West Crossing with an angle larger than 1.5° and a radius of curvature less than 100x diameter. There were no bends on either crossing segment that were characterized as *tight* (having bend radii of 5x diameter or less).

Of the 20 bends on the East Crossing, only two (BND 10 and BND 11) were located in the portion of the pipeline where the pipeline was installed on top of the lakebed; the rest were located in the trenched portions of the crossing. Of the 23 bends on the West Crossing, only 5 (BND 9 to BND 13, inclusive) were located in the portion of the pipeline where the pipeline was installed on top of the lakebed. While it was not possible to determine the origin of each bend, it is likely that bends located on the onshore portions of the crossing are field or factory bends that are part of the design. The remainder of the bends may have been intentionally or unintentionally created as part of the installation process.

As field construction practices do not permit bending through girth weld areas, a review of each bend was undertaken to evaluate proximity to girth welds. Two bends, both found on the West Crossing segment, were found within 3 ft. (0.9 m) of a girth weld. BND 9 is located 2.79 ft. (0.85 m) from Girth Weld No. GWD 6060 at absolute distance of 15,419.97 ft. (4,700 m), and BND 12 is located 2.93 ft. (0.89 m) from Girth Weld No. GWD 6110 at absolute distance of 15,532.15 ft. (4,734.19 m). These girth weld locations were cross-referenced to the 2014 Oceaneering Pipetech Tethered crack tool feature lists to determine if strain in the vicinity of the bends might have caused girth weld cracks. The Oceaneering tethered in-line inspection crack tool stops at each girth weld location to examine the weld condition with high resolution ultrasonics. While no cracks were noted on the Oceaneering tethered in-line inspection reports through the lengths of either the East or West segments, no other weld anomalies were identified in girth weld numbers GWD 6060 or GWD 6110, or in adjacent girth welds either.

In the West Straits Crossing segment, two features (both ovalities) were identified that exceeded the reporting criteria. One ovality had a maximum deflection of 8.75% nominal OD, and the other had a maximum deflection of 5.45% nominal OD. While significant ovalities can, under certain circumstances impair the passage of in-line inspection tools, the strain associated with these features is normally broadly distributed around the pipe circumference, and thus, ovality is not generally considered to be a feature that poses an integrity threat.

2.4.1.1.1.3.6.3 2016 Geopig Inspection (Baker Hughes)

A review of the 2016 Baker Hughes *Geopig Inspection Report* was completed. The reporting thresholds for that inspection were:

- dents and wrinkles ≥2% of nominal OD
- multi-apex geometric anomalies ≥1% of nominal OD
- top-side geometric anomalies >0.5% nominal OD and in close proximity to a dent, or geometric anomalies ≥1% nominal OD
- bottom-side geometric anomalies >0.5% nominal OD and in close proximity to a dent ≥2% nominal OD
- ovalities ≥ 5% nominal OD
- areas of pipeline movement with bending strain difference exceeding 0.1% and spanning more than one pipe joint.

In the East Straits Crossing segment, none of the reporting criteria were exceeded.

In the West Straits Crossing segment, two features (both ovalities) were identified that exceeded the reporting criteria. One ovality had a maximum deflection of 9.2% nominal OD, and the other had a maximum deflection of 5.7% nominal OD. As noted above, while significant ovalities can, under certain circumstances, impair the passage of in-line inspection tools, the strain associated with these features is normally broadly distributed around the pipe circumference, and thus, ovality is not generally considered to be a feature that poses an integrity threat.

2.4.1.1.1.3.7 Equipment Failure (Failure of Non-Pipe Pressure-Retaining Equipment)

Equipment failure is related to the failure of pumps, valves, seals, O-rings, meters, pressure switches, temperature gauges, prover loops, scraper traps, strainers, truck loading racks, etc., which are associated with the types of equipment found mostly at terminals and pump stations. Because of the number and variety of types of non-pipe equipment associated with these sorts of installations, and because of the wide range of connection mechanisms, control systems, and associated pressure envelope designs, the threat of equipment failure accounts for the greatest number of releases in hazardous liquids pipeline systems, although the vast majority of these failures are leaks.[13] Because of increased presence and monitoring at operator-controlled stations, and because of the use of on-site containment systems such as dykes and sumps, these leaks are normally confined to the operator's property.

On Line 5, there is no non-pipe pressure-containing equipment below the Straits and this type of equipment is present in only a very limited extent at the valve sites on the north and south sides of the Straits Crossing.

2.4.1.1.1.3.8 Immediate Failure due to Mechanical Damage

In onshore pipelines, the greatest threat associated with mechanical damage is excavating equipment, such as backhoes, trenching equipment, augers, etc., in the form of third parties operating without adequate supervision, or from first parties (Operator's own activities), or second parties (Contractors, acting on behalf of the operator), who inadvertently strike an operating pipeline with heavy equipment. Failures have occurred as a result of vandalism as well, although at much lower levels of significance than those associated with inadvertent external interference. In offshore pipelines, the greatest threat associated with mechanical damage is shipping activity, such as dropped objects (principally a concern only in the vicinity of production platforms), trawl board damage (confined to ocean environments where bottom trawling is used), or inadvertent anchor deployment and dragging. This last mechanical damage category, which involves the threat of pipelines being hooked by anchors that are unintentionally dropped while ships are underway, and subsequently dragged, has seen a heightened focus on the part of pipeline owners and operators, due to an increased in frequency. [71, p. 23]

The anchor hooking scenario involves a ship that is underway, and that for some reason deploys one of its anchors. This scenario involves the possibility (supported by actual scenarios) that the turnbuckle and its hook (located on the anchor winch) may not be in good working condition, or may be incorrectly applied. [71, pp. E-2 - E-3] In bad weather when there is movement in both the ship and the anchor, snatches may cause the chain stopper to break or jump. Since there is no load in the part of the chain between the winch and the chain stopper, a braking chain stopper would cause a jerk in the chain. Since the chain lock is primarily used for securing the chain while the ship is at anchor, it cannot be said for sure that the lock is always applied or applied in adequate way at all times while the ship is underway. There are numerous recorded incidents involving unsatisfactorily maintained or dysfunctional band brakes from related industries,

[13] A review of the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration Incident Statics for Hazardous Liquids Pipelines (2010 – 2016 incl.) indicated that equipment failure accounted for over 45% of all failures. Ruptures accounted for only 0.9% of all Equipment Failures.

meaning that a band break may not necessarily be capable of stopping a free falling anchor.

After having unintentionally dropped the anchor, the inadvertent anchor drop may or may not be discovered within a short period of time, and interaction with a pipeline may occur either without the anchor becoming seated (providing that the pipeline is not buried too deeply), or after the anchor has penetrated.

The level of threat associated with anchor drag is primarily a function of the following factors:

- size of pipeline
- water depth (relative to anchor chain length)
- pipeline protection (depth of burial, use of armoring material)
- number, and size distribution of ship crossings per unit time.

While there have been no incidents involving anchor strike (drag/drop) in the operating history of the Straits pipelines [72], it must be noted that with respect to the above vulnerability factors, the Straits Crossing segments cross a busy shipping lane (see Figure 2-6), where they lie exposed on top of lakebed with no protective cover. They also are situated in water that is shallow, relative to the anchor chain lengths of most cargo vessels. Furthermore, a 20-in. diameter pipeline is small enough to fit between the shank and flukes of a stockless anchor for a large cargo vessel, and thus, is physically capable of being hooked.

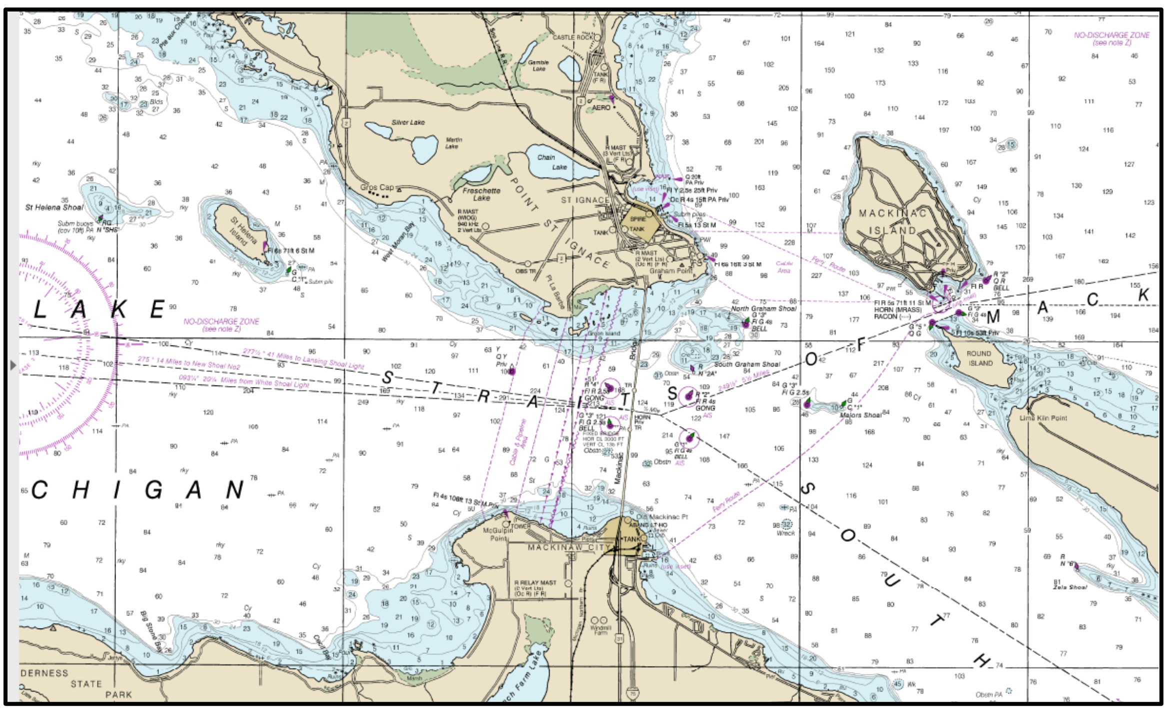


Figure 2-6: Detail of Chart of De Tour Passage to Aaugoshance Point [73]

2.4.1.1.1.3.9 Time-Dependent Failure Due to Resident Mechanical Damage

Dents and gouges caused by installation damage (see Section 2.4.1.1.1.3.6) or external interference (see Section 2.4.1.1.1.3.8) that do not result in immediate failure may, if they go undiscovered, become more severe with the passage of time such that eventually they cause a leak or a rupture. In order for pre-existing sub-critical damage to become more severe with the passage of time, a growth mechanism is required. Potential growth mechanisms are corrosion, environmental cracking, ductile tearing due to external forces or pipe movement, or pressure-cycle-induced fatigue. [35, p. 77] Mechanical damage is readily detected with in-line inspection metal loss tools and geometry tools, especially if used in combination, and this is the best means to locate and mitigate any such anomalies.

A review of Enbridge's 2013 MFL inspection and 2016 geopig inspection data showed no evidence of resident damage, however it is feasible that sub-critical damage could occur in the future as a result of external interference (most particularly, accidental damage due to inadvertent anchor deployment and drag). The scenarios that might result in pipeline damage from this form of external interference involve dragging an anchor through the Straits where there is heightened concern and awareness of submarine infrastructure, such as buried communication/electrical cables, and pipelines. Consequently, it is almost impossible to foresee a circumstance whereby a serious incident of this nature could go both undetected and unreported.

2.4.1.1.1.3.10 Incorrect Operations

The threats to transmission pipeline integrity from incorrect operations include, but are not necessarily limited to accidental over-pressurization, exercising inadequate or improper corrosion control measures, and improperly maintaining, repairing, or calibrating piping, fittings, or equipment. Investigations of pipeline failures invariably identify root causes as related to management systems, including procedural, process, implementation or training factors as root causes, and in that respect incorrect operations plays a role in virtually all pipeline failures, regardless of the direct cause.

There have been two overpressurization events at the North Straits station in the past 5 years. In both cases, MOP overpressures were case overpressures within North Straits station, and the affected piping was not within the span of Line 5 that is underwater. [74]

Following the 2010 Marshall incident, Enbridge undertook various initiatives to improve its operations. [75] These improvements are summarized as follows:

- Implementation of Integrated Management System to align all management systems to enable Enbridge to monitor and improve performance.
- Implementation of changes to all levels of environmental organization structure to better manage control of operations, including the creation of a new emergency preparedness position.
- Enhancement to Environmental Management System, including incident command training and enhancements to incident response plan.
- Implementation of cross-business unit emergency response teams, with annual training exercises.

- Implementation of gap analyses and process improvements in areas of contractor safety management, process safety management, incident investigation, management of change, office and off-the-job safety.
- Revised Public Awareness Program elements.
- Creation of the pipeline control systems and Leak Detection Department, resulting in additional staffing dedicated to areas of pipeline control and leak detection.
- Implementation of changes to processes and procedures related to pipeline control and leak detection, including increased training and establishment of a Quality Management System.
- Changes to instrumentation for pipeline control and leak detection, and establishment of a Maintenance Management Program to formalize the inventory and management of critical leak detection equipment.
- Changes to the Material Balance System (MBS) for leak detection, and implementation of new leak detection technologies
- Changes to the Supervisory Control and Data Acquisition (SCADA) System to improve controller decision support systems, including analysis of column separation and potential leak events.
- Organizational structure changes to pipeline control.
- Changes to key procedures and processes, such as pipeline startup, shutdown, MBS alarms, column separation identification, incident investigation, shift change, and fatigue management.
- Implementation of a new Control Room Management Plan.
- Development and enhancement of training programs related to leak identification, incident investigation, emergency response, and fatigue management.
- Enhancements top Control Center Safety Culture, and Control Center Human Factors.
- Changes to the Integrity Management Department, including Risk Management, System compliance, and facility integrity.
- Creation of a new Asset Integrity Department, focused on operational optimization, due diligence, and long-term pipeline maintenance strategies.
- Adoption of reliability methods to analysis of in-line inspection data.
- Increase in manpower dedicated to facilities integrity.
- Creation of an Integrity Services Department, responsible for quality management, information management, and in-line inspection technology.
- Creation of a Logistics Department, responsible for design, execution and scoping of all in-line inspections and main line projects.
- Creation of a Planning group, responsible for planning and analysis of integrity assessment activities.
- Implementation of changes to procedures related to the Integrity Management Program.

2.4.1.1.1.3.11 Weather and Outside Force

The threat of weather and outside force pertains to discrete, localized hazards associated with potential weather-related events (such as floods or lightning strikes), geohazards (such as slope failure or rock fall), seismic hazards (including lateral spreading due to soil liquefaction), and hydrotechnical forces (such as scour, or vortex-induced vibration) that may or may not be present at discrete, specific locations along a pipeline segment (see Attachment 3 in Appendix S). Where attributes associated with any of the above threats are present at a given location, the associated pipeline segment is considered to be vulnerable to failure due to that threat mechanism; otherwise, absent vulnerability factors, the pipeline is not considered to be vulnerable. By way of example, a slope is required in order to be vulnerable to slope failure, and a river is required in order to be vulnerable to river scour.

The geotechnical/hydrotechnical review of the Straits Crossing segments indicated that the only viable threat mechanisms were those associated with spanning (over-stress of the pipe section due to the combination of gravity and drag forces, as well as vortex-induced vibration due to vortex-shedding of water current around the pipeline).

2.4.1.1.1.3.12 Activation of Resident Damage from Pressure-Cycle Induced Fatigue

Resident sub-critical damage may become activated, and may grow to a critical size under the influence of pressure-cycle induced fatigue. Such damage may be attributed to any of a variety of defects, as described in Sections 2.4.1.1.1.3.1 (External Corrosion), 2.4.1.1.1.3.2 (Internal Corrosion), 2.4.1.1.1.3.3 (Selective Seam Corrosion), 2.4.1.1.1.3.4 (Stress Corrosion Cracking), 2.4.1.1.1.3.5, (Manufacturing Defects), 2.4.1.1.1.3.6 (Construction and Fabrication Defects) or 2.4.1.1.1.3.9 (Resident Mechanical Damage). Any longitudinally oriented anomaly of sufficient size has the potential to become enlarged by pressure-cycle-induced fatigue. [35, p. 78] Repeated cycles of stress are known to cause defects above a certain threshold size to grow, and if the growth continues long enough, the defect can cause structural failure.

The severity of this threat is strongly dependent on the initial size of the defect, the aggressiveness of the pressure cycles in terms of stress range and frequency, and the effective crack-growth rate. Regular in-line inspections, using tools that are capable of identifying potential resident damage, along with fatigue analysis are considered effective measures of managing this threat. With respect to this last point, high-resolution axial MFL and geometry inspections of the Straits Crossing segments of Line 5 have been conducted at a minimum inspection interval of five years since 1998, with the most recent geometry inspection in 2016. Both lines were inspected in 2014 with ultrasonic tools for circumferentially oriented cracking.

2.4.1.1.1.3.12.1 Pressure Cycle Severity Assessment

The severity of pressure cycles are a function of the magnitude and frequency of individual pressure cycles that exist within the operating pressure spectrum of a pipeline. In that respect, many smaller fluctuations in pressure can contribute as much to fatigue severity as fewer fluctuations that are larger in magnitude.

In order to characterize the severity of the operating pressure spectra of a pipeline, it is necessary to determine an equivalent number of cycles for a nominal stress range. This is accomplished using the Palmgren-Miner rule for Cumulative Damage in Fatigue. This rule states that failure occurs where (see Equation 2-2):

$$\sum_i D_i = \sum_i \frac{n_i}{N_i} \geq 1$$

Equation 2-2: Palmgren-Miner Rule

Where:

D_i = Damage fraction due to stress range i

n_i = Number of cycles accumulated over stress range i

N_i = Number of cycles to failure for stress range i

In the general case of defect growth by fatigue, the effect of the entire pressure spectrum is used to determine how much of the overall fatigue life of the pipe has been consumed. The operating pressure spectrum associated with a pipeline will consist of an assortment of pressure fluctuations of varying magnitudes. Each pressure range within an operating pressure spectrum can be characterized by the cumulative amount of damage that it contributes to the overall fatigue life of the defect. By assigning a cumulative damage value to each pressure range within a pressure spectrum, and summing the damage values for all pressure ranges, an equivalent number of cycles over a uniform (constant amplitude) pressure range can then be determined.

In order to evaluate the pressure spectrum of a pipeline, the pressure spectrum is broken down into 'bins' of pressure ranges, and the number of cycles within each pressure range is counted using an established method called 'Rainflow Analysis'. [76] Using the Rainflow Analysis algorithm, the operating pressure spectrum is summarized and simplified for use in fatigue analysis by presenting pressure cycle magnitude and frequency in the form of a histogram. Table 2-6 shows the pressure cycling severity guide based on pressure ranges and corresponding annual frequency.

Table 2-6: Stress Cycle Severity Guide

Range, %SMYS	Very Aggressive	Aggressive	Moderate	Light
65 to 72	20	10	2	0
55 to 65	40	20	4	0
45 to 55	100	50	10	0
35 to 45	500	250	50	50
25 to 35	1,000	500	100	100
20 to 25	2,000	1,000	200	200

Using the pressure cycle severity evaluation procedure discussed above, a pressure cycle analysis was conducted to characterize the pressure cycling severity of the Straits Crossing segments. The operating pressure data from September 1st, 2015 to September 14th, 2016 at a 12-hour interval were used for the analysis. [77]

The result of the Rainflow Analysis performed on the operating pressure spectrum of the Straits Crossing segments is provided in Figure 2-7.

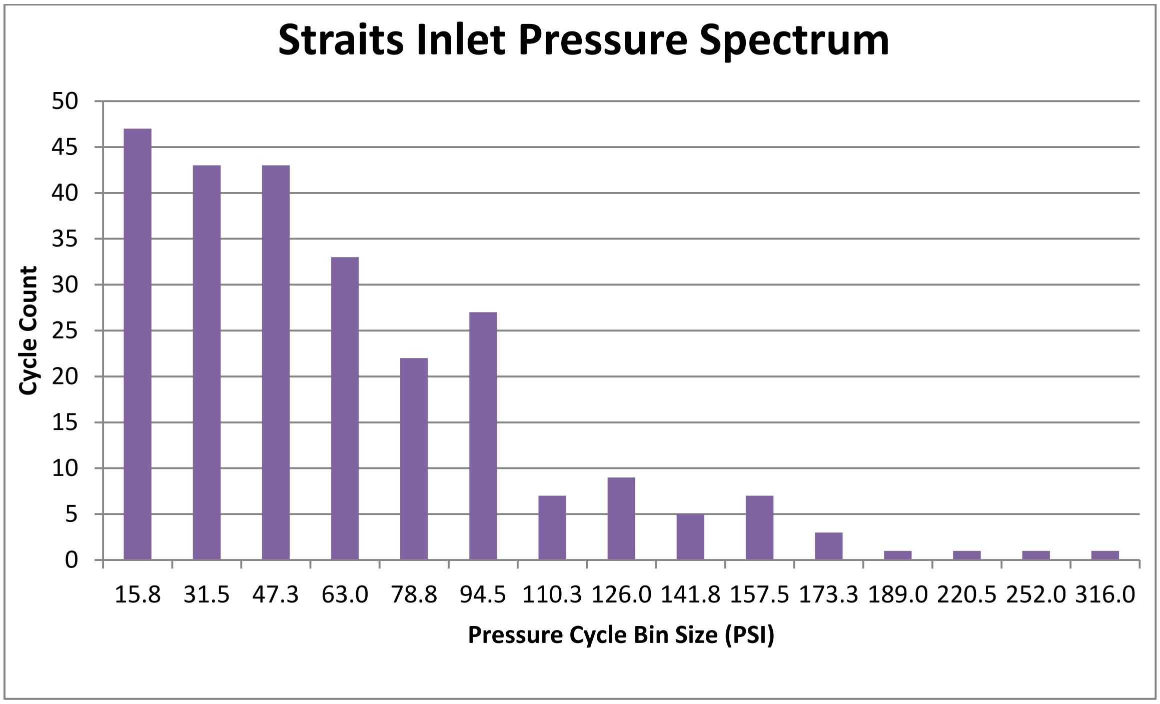


Figure 2-7: Pressure Spectrum for Straits Crossing

Using The Palmgren-Miner Linear Damage Principle, the estimated equivalent pressure cycle for the Straits pipelines was determined to be 5 cycles at 20% SMYS. Based on the above analysis and the severity classifications in Table 2-6, the pressure profile for the Straits Crossing segments is classified as *Light*.

2.4.1.1.1.4 Summary of Threat Potential

In quantitative risk assessment, the goal of the frequency analysis is to estimate the probability of loss of containment in quantitative and normalized terms (i.e., probability of failure over a defined pipe length, per year of operation). Typically, these frequency estimates vary significantly from threat to threat, with the threats that contribute the most to overall failure likelihood being orders of magnitude greater than other threats. The confidence associated with making an estimate of failure likelihood depends largely on the data and methodological approaches available to make those estimates, and so the magnitudes of the threats of lesser significance are often smaller than the magnitude of the smallest significant digit of the threats that dominate the overall threat environment. Therefore, the most practical approach is to identify those threats that have the potential to dominate the overall threat environment, and to direct best efforts at quantifying the failure likelihood values associated with those threats; not necessarily to make quantitative estimates of all threats.

As outlined in Section 2.4.1.1.1.2, one of the goals of the *Threat Assessment* is to classify each threat into one of two categories:

- Principal Threats (those threats for which an evaluation of susceptibility attributes indicates a significant vulnerability, and that have the potential to provide the most significant contributions to overall failure probability).

- Secondary Threats (those threats for which an evaluation of susceptibility attributes indicates a relatively insignificant or non-significant vulnerability and that therefore have the potential to contribute only at a second-order or potentially negligible levels in terms of overall failure probability).

In the failure probability analysis, best efforts are directed at quantifying the failure likelihood values associated with the Principal Threats.

Another goal of the *Threat Assessment* is to establish the optimal basis for making quantitative estimates of failure likelihood, based on an evaluation of data availability, quality and accuracy, and the availability established approaches for each threat. In that regard, while industry failure statistics are available, and can be used to make quantitative estimates of failure likelihood, that is not always the optimal approach. This is because failure incident data do not always accurately reflect site-specific conditions, materials, operating environments and practices. [78] Where limit state models are available to mathematically describe conditions associated with the onset of failure, and where data to describe the variables contained in those limit state models are available, reliability methods often represent the preferred approach, as they inherently account for material properties, design and operating conditions associated with the pipeline being modeled. For some threats, however, lack of availability of limit state models and/or data to use in conjunction with those models preclude the use of reliability methods, and other approaches, including the use of industry incident data (selected so that it represents, as much as possible, the infrastructure being modeled), must be used.

The following sections summarize the evaluation of threat attributes, identifies those threats that fall within each of the two categories of Principal Threats and Secondary Threats, and where applicable, identifies optimal approaches for making quantitative estimates of failure likelihood.

2.4.1.1.1.4.1 Principal Threats

Based on an evaluation of susceptibility attributes described in Section 2.4.1.1.1.3, the following threats have been identified as Principal Threats:

- Immediate Failure due to Mechanical Damage
- Weather and Outside Force
- Incorrect Operations.

2.4.1.1.1.4.1.1 Immediate Failure due to Mechanical Damage

As outlined in Section 2.4.1.1.1.3.8, for the Straits Crossing segments of Line 5, the principal potential source of mechanical damage is interaction with anchors from ships that are underway, and that may inadvertently deploy and drag one of its anchors. The level of threat associated with anchor drag is primarily a function of the following factors:

- number, and size distribution of ship crossings per unit time
- water depth (relative to anchor chain length)
- size of pipeline
- pipeline protection (depth of burial, use of armoring material).

With respect to the above vulnerability factors, the 20-in. Straits Crossing pipe segments have the following attributes:

- They cross a busy shipping lane, where they lie exposed on top of lakebed with no protective cover.
- They are situated in water that is shallow, relative to the anchor chain lengths of most cargo vessels.
- A 20-in. diameter pipeline is small enough to fit between the shank and flukes of a stockless anchor for a large cargo vessel, and thus, is physically capable of being hooked

Failure Probability Estimation

A standardized approach has been developed based on the above vulnerability factors [71], and this approach has been adopted to make quantitative estimates of the annual probability of pipeline failure due to anchor-hooking.

Failure Mechanism

Due to the displacement controlled nature of anchor interaction with a pipeline, the failure mechanism associated with this threat is characterized as an FBR.

2.4.1.1.1.4.1.2 Weather and Outside Force

As outlined in Section 2.4.1.1.1.3.11, the assessment of attributes of the threat of Weather and Outside Force for the Straits Crossing segments identified two viable threat mechanisms – both of which are associated with spanning:

1. Over-stress of the pipe section due to the combination of gravity and drag forces.
2. Vortex-induced vibration due to vortex-shedding of water current around the pipeline.

Failure Probability Estimation

An existing dataset based on Acoustic Doppler Current Profiler (ADCP) buoys is available, which was used to calibrate the hydrodynamic model used for modeling spill behavior see Attachment 2 in Appendix S. Because water currents change with position and over time, temporal outputs of this model were employed to model water current magnitude as a random variable at locations that correspond with the positions of the East and West Straits Crossing segments. In conjunction with the water current model, span inspection data collected over the course of the years 2005 – 2016 were leveraged to model span length as a random variable. Collectively, these data were leveraged in conjunction with mechanistic models to undertake a reliability-based analysis of failure likelihood due to spanning and due to vortex-induced vibration.

Failure Mechanism

Based on past outside force incidents, the failure mechanism associated with this threat is characterized as an FBR.

2.4.1.1.1.4.1.3 Incorrect Operations

As outlined in Section 2.4.1.1.1.3.10, since the Marshall incident in 2010, Enbridge has undertaken a review and upgrade of the management systems by which it controls its pipeline operations. Despite this, numerous pipeline investigation analyses have shown that regardless of the direct cause, some element of incorrect operations, such as procedural, process, implementation or training factors invariably plays a role in the root causes of pipeline failure. Furthermore, it is often impossible to foresee in advance what sequence of events and breakdown in management systems and operating practices might lead to failure. For this reason, failures that are related to incorrect operations cannot be discounted, and are considered a Principal Threat.

Failure Probability Estimation

The US DOT's Pipeline and Hazardous Materials Safety Administration's Hazardous Liquids Failure Incident Database was used to provide historical estimates of failure likelihood associated with incorrect operations in offshore transmission pipeline infrastructure in liquids service (e.g., crude oil and NGLs).

Failure Mechanism

Due to the range of conditions leading to a failure that are considered under this threat, the distribution of potential hole sizes is broad. For the purposes of associating failures attributed to incorrect operations with consequences in the determination of risk, a 3-in. (75 mm) diameter hole was determined through probability-weighting the distribution of hole sizes for offshore pipelines. [71, p. 40]

2.4.1.1.1.4.2 Secondary Threats

Secondary Threats, defined as those threats for which an evaluation of susceptibility attributes indicates a relatively insignificant vulnerability and that therefore have the potential to contribute only at a second-order level in terms of overall failure probability, include the following:

- external corrosion
- internal corrosion
- selective seam corrosion
- stress corrosion cracking (SCC)
- construction and fabrication defects
- manufacturing defects
- equipment failure (non-pipe pressure containing equipment)
- time-dependent failure due to resident mechanical damage
- activation of resident damage from pressure-cycle-induced fatigue.

2.4.1.1.1.4.2.1 External Corrosion

As highlighted in Section 2.4.1.1.1.3.1, vulnerability to the threat of failure due to external corrosion is related to coating type, coating condition, CP, corrosion assessments, and operating experience.

With respect to the above vulnerability factors, the 20-in. Straits Crossing pipe segments have the attributes described in following sections.

Coating

The Straits Crossing segments are coated with coal tar enamel (CTE) coating, which, although considered a vintage coating system discontinued after the mid-1980s, generally has a very good performance history, displaying good adhesion, and forming a continuous, strong bond that is resistant to moisture absorption and deterioration over time. Significantly, unlike other coating systems, CTE does not shield CP currents. While there has been some public concern expressed over the reference to coating holidays and delaminations in Enbridge's *Biota Work Plan*, it was clarified that those references to coating damage were made necessary by the conditions of the *Consent Decree*. This is because it was the *Consent Decree* that mandated the creation of the *Biota Work Plan*, and which required that Enbridge conduct special investigations at areas of potential coating damage. Enbridge further clarified that the only coating damage it has identified to date involves the CTE outer-wrap, which in some cases, has become separated from the underlying coating material, which is still in contact with the pipe surface. This assertion is supported by the Cathodic Protection Current Mapping (CPCM) inspection conducted in September 2016. This tool is designed to measure current density continuously along the length of the pipeline, as well as the location and magnitude of current leaving or entering the pipeline, which would be expected to occur at significant holiday locations. The fact that this tool reported no current density anomalies supports the contention of an intact coating. Other findings of significance are that low levels of current density along the entire length of the pipelines indicate that the coating is in excellent condition on both the East and West Crossing segments. Finally, in the author's experience, it is not unusual for the outer layer of CTE coatings to separate from the underlying corrosion coating, with no apparent compromise made to the corrosion protection performance of the coating.

Cathodic Protection

While the results of the 2016 CPCM inspection of the East and West Crossing segments indicated that the current demand was low is largely attributed to coating performance, this finding is significant from the perspective of the demands on the CP System. Specifically, because there are relatively low demands on the CP System, it should be readily capable of imparting protective currents along the length of the pipe segments. This is supported by a review of CP potential survey records dating back to 1989, which show no sub-criterion readings.

Corrosion Assessments

High-resolution MFL in-line inspections of the East and West Straits Crossing pipelines has been completed every five years since 1998, with the most recent inspection being completed in 2013. A review of the inspection reports indicated that the only external metal loss features identified on both the East and West Straits Crossing segments were those associated with manufacturing anomalies for which no mechanism exists for growth. An analysis of the growth of matched external metal loss anomalies between the 2008 MFL and 2013 MFL inspections indicated that all variances in depth were found to be within the ±10% error of the tool. Therefore considering tool error, there is no growth of wall loss features; this consistent with these features being manufacturing anomalies, rather than active, growing corrosion features.

Operating Experience

The lack of vulnerability to failure by means of external corrosion on the Straits Crossing segments of Line 5 is consistent with operating experience for offshore pipeline segments, which dictates that apart from offshore platform risers, cases of significant external corrosion on offshore pipelines are extremely rare [51, p. 15]. This is owing to the homogeneity of the offshore environment, the predictability of coating and CP due to uniformly high conductivity of the environment, and the creation of any exposed metal with calcareous deposits, which acts to inhibit corrosion.

Failure Probability Estimation

Reliability approaches exist to model failure probability based on in-line inspection data. [79] These approaches employ a limit state model in conjunction with ILI data, where feature size distributions are developed based on nominal dimensions and tool measurement error. Feature-specific growth rate distributions are developed as part of the analysis, which incorporate probability density functions describing wall thickness and material strength distributions, along with a model error function to establish the probability of failure as a function of time. By incorporating the re-assessment interval, the probability of failure within a segment in the interval between assessments can be determined. Nevertheless, this approach is predicated upon the availability of a population of actively growing corrosion defects, as detected by an in-line inspection tool. In the absence of any detectable corrosion features, the analysis will return a failure probability estimate of zero. While the probability of failure due to a time-dependent threat such as external corrosion is never truly zero over a set period of time, the absence of detectable external corrosion features within the Straits Crossing segments after 64 years of operation suggests that this particular threat does not contribute to the overall probability of failure at a magnitude that is significant relative to that which is associated with the Principal Threats. For this reason, failure probability estimates for this threat have not been generated.

2.4.1.1.1.4.2.2 Internal Corrosion

As highlighted in Section 2.4.1.1.1.3.2, vulnerability to the threat of failure due to internal corrosion is related to product stream characteristics (composition and flow conditions), including receipt point product stream composition, corrosion assessment data, and mitigation programs.

With respect to the above vulnerability factors, the 20-in. Straits Crossing pipe segments have the attributes described in the following sections.

Product Stream Characteristics

The products transported along Line 5 are subject to a tariff specification that limits basic sediment and water (BS&W) to 0.5%. This is low, relative to typical U.S. tariffs, which limit BS&W to 1% in most cases. [80, p. 29] The flow rate maintained during operations results in turbulent flow, which acts to entrain what water and solids that may exist within the product stream. While shut-downs might act to allow water and sediment to settle and accumulate at the bottom of the pipe, a review of operating data indicates that shut-down periods are relatively limited in duration, and are rare in actual practice. Under conditions of turbulent flow, product streams that are limited to 0.5% BS&W do not generally present a corrosion concern. [81, p. 19]

Corrosion Assessments

High-resolution MFL in-line inspections of the East and West Straits Crossing pipelines have been completed every five years since 1998, with the most recent inspection being completed in 2013. A review of the inspection reports indicated that the only internal metal loss features identified on both the East and West Straits Crossing segments were those associated with manufacturing anomalies for which no mechanism exists for growth. An analysis of the growth of matched internal metal loss anomalies between the 2008 MFL and 2013 MFL inspections indicated that all variances in depth were found to be within the ±10% error of the tool. Therefore, considering tool error, there is no growth of wall loss features, as would be expected if these are all manufacturing anomalies, rather than active, growing corrosion features.

Mitigation Programs

Enbridge does not employ chemical injection or cleaning programs on the Straits Crossing segments.

Failure Probability Estimation

The same ILI-based reliability approaches that were discussed in the context of external corrosion are applicable to internal corrosion. As with external corrosion feature analysis, the probability of failure as a function of time is generated, and by incorporating the re-assessment interval, the probability of failure within a segment in the interval between assessments can be determined.

This approach is predicated upon the availability of a population of actively growing corrosion defects, as detected by an in-line inspection tool, and in the absence of any detectable corrosion features, the analysis will return a failure probability estimate of zero. While the probability of failure due to a time-dependent threat such as internal corrosion is never truly zero over a set period of time, the absence of detectable internal corrosion features within the Straits Crossing segments after 64 years of operation suggests that this particular threat does not contribute to the overall probability of failure at a magnitude that is significant relative to that which is associated with the Principal Threats. For this reason, failure probability estimates for this threat have not been generated.

2.4.1.1.1.4.2.3 Selective Seam Corrosion

As highlighted in Section 2.4.1.1.1.3.3, this threat is not considered applicable to the 20-in. Straits Crossing segments due the fact that these pipe segments were constructed of seamless pipe.

2.4.1.1.1.4.2.4 Stress Corrosion Cracking

As highlighted in Section 2.4.1.1.1.3.4, vulnerability to the threat of failure due to SCC is primarily influenced by material susceptibility, environment, and stress level. The susceptibility to SCC in the Straits Crossing segments is judged to be extremely low due to the following factors:

- In order for SCC to initiate, the corrosion coating needs to have deteriorated to the point where the external environment has come into contact with the pipe surface. As discussed in Section 2.4.1.1.1.3.1, there is no evidence to suggest that this has occurred. While there is some evidence that the outer wrap of the CTE coating may have separated from the underlying coating, that underlying coating appears to be well bonded to the pipe surface. This is supported by the findings of the 2016 CPCM surveys of the East and West Straits segments, the reports for which indicated that the corrosion coating on the East and West Straits segments is *in excellent condition*.
- Near-neutral pH SCC is normally associated with some evidence of external corrosion; however, in the most recent (2013) MFL surveys of the East and West Straits segments, there is no evidence of any external corrosion.
- Since CP acts to raise the pH of the environment at the pipe surface, near-neutral pH SCC is normally associated with corrosion coating systems that shield CP currents. The CTE coating system that has been used on the Straits Crossing segments does not shield CP current.
- High-pH SCC is normally associated with elevated operating temperatures above 100°F (38°C); however, a review of operating records indicated that the MOP temperature upstream of the Straits Crossing is at least 16°F (9°C) below that threshold.
- The MOP of 600 psi (4,137 kPa) results in an operating stress level of 21% of SMYS. This is well below the 60% operating stress level that is associated with SCC.

Failure Probability Estimation

While the probability of failure due to SCC cannot be ruled out in absolute terms over a set period of time, the absence of vulnerability factors in the Straits Crossing segments suggests that this particular threat does not contribute to the overall probability of failure at a magnitude that is significant relative to that which is associated with the Principal Threats. For this reason, failure probability estimates for this threat have not been generated.

2.4.1.1.1.4.2.5 Construction and Fabrication Defects

As outlined in Section 2.4.1.1.1.3.6, there is evidence that control over welding processes, including x-ray inspection of 100% of all girth welds, exceeded what was typical for the era during the installation of the Straits Crossing segments. Nevertheless, a review of in-line inspection data indicates that there are numerous features present within the girth welds that would likely be characterized as repairable defects under current welding inspection practices. In particular, significant amounts of porosity and lack of fusion were noted within the girth welds of both Straits Crossing segments. Nevertheless, because a pipeline’s principal operating stresses lie in the same plane as most girth weld defects, such defects rarely result in pipeline failure, particularly in the absence of some mechanism for the growth of sub-critical flaws.

Failure Probability Estimation

The *Threat Assessment* demonstrated that the greatest potential for outside force that could result in girth weld failure arises from spanning stresses, vortex-induced vibration and anchor interaction. All three are being treated as separate failure mechanisms, for which failure probability values are being derived. In particular, the potential presence of weld zone defects is integral to the approaches used for estimating failure probability associated with spanning phenomena. Therefore, the failure probability associated with Construction and Fabrication Defects is subsumed within the determination of failure probability, and is being considered as part of the failure probability calculations for those other threats, and will not be repeated as a separate calculation under the threat category of Construction and Fabrication Defects.

2.4.1.1.1.4.2.6 Manufacturing Defects

A review of the in-line inspection results for the Straits Crossing segments shows ample evidence of manufacturing anomalies that are typical of vintage seamless pipe manufacturing processes, such as wall thinning, slivers and laminations. The 2013 MFL inspection showed that approximately 10% of the pipe joints on the East Segment and approximately 17% of the pipe joints on the West Segment have wall loss anomalies. Nevertheless, none of these features were found to be structurally significant, and unless acted upon by some form of external loading, or by fatigue, they will not threaten the structural integrity of the pipeline. A review of the operating pressure spectrum associated with the Straits crossing segments discounted the potential for significant fatigue loading due to operating pressure cycles. The *Threat Assessment* demonstrated that the greatest potential for outside force that could result in girth weld failure arises from spanning stresses, vortex-induced vibration and anchor interaction, for which failure probability values are being derived as part of separate analysis.

Failure Probability Estimation

Several factors were considered in arriving at a conclusion that the probability of failure within the Straits Crossing segments due to the threat of manufacturing defects is not significant relative to the contribution of the Principal Threats:

- A review of in-line inspection data indicates that while numerous manufacturing anomalies are present within the Straits Crossing segments, none are considered structurally significant. The installation hydrostatic test demonstrated a minimum factor of safety of 2.0 on existing manufacturing defects. A hydrostatic test to reconfirm this factor of safety is planned for both the East and West Straits pipelines in or about June of 2017. [63]
- The existing manufacturing anomalies would require some mechanism for flaw growth (fatigue), or significant overload in order to result in pipeline failure
- The *Threat Assessment* demonstrated that the greatest potential for outside force arises from spanning stresses, vortex-induced vibration and anchor interaction. All three are being treated as separate failure mechanisms, for which failure probability values are being derived as part of separate analysis.

- An assessment of the operating pressure spectra associated with the Straits Crossing segments resulted in the lowest-possible pressure-cycle fatigue rating ('Light'). This pressure cycle regime is not associated with industry experience of pressure-cycle-induced fatigue failures of pre-existing sub-critical flaws.

Finally, a review of incident data suggests that failures due to manufacturing defects are rare in offshore pipelines. A comprehensive report on failure statistics by cause for offshore hazardous liquid pipelines is maintained by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) [2]. This database contains pipeline failure statistics for more than 5,100 mi. (8,208 km) of offshore hazardous liquids pipeline infrastructure in the US. A review of this database was completed for the years 2002 through 2016, inclusive, representing 76,856 mi.-y of offshore operating history. A filter was applied to exclude incidents associated with offshore platforms and wellhead flow lines. Within that record there were no failures attributed to line pipe manufacturing defects. This is likely attributable to the higher wall thicknesses (and correspondingly lower operating stress levels) typically used in offshore pipelines, relative to onshore pipelines, which can operate at up to 80% of the specified minimum yield strength of the line pipe material. The Straits Crossing segments, which at their maximum operating pressure operate at 21% of the minimum yield stress of the line pipe material, are typical of offshore pipeline infrastructure in this regard.

Collectively the information reviewed suggests that this particular threat does not contribute to the overall probability of failure at a magnitude that is significant relative to that which is associated with the Principal Threats. For this reason, failure probability estimates for this threat have not been generated.

2.4.1.1.1.4.2.7 Equipment Failure

As highlighted in Section 2.4.1.1.1.3.7, the threat of Equipment Failure relates to the failure of non-pipe pressure-retaining equipment, such as pumps, valves, seals, O-rings, meters, pressure switches, temperature gauges, prover loops, scraper traps, strainers, truck loading racks, etc. This type of equipment is normally associated with installations such as terminals and pump stations, where failures attributed to this threat category typically manifest themselves as readily-contained leaks, rather than large releases. On Line 5, there is no non-pipe pressure-containing equipment below the Straits, and this type of equipment is present in only a very limited extent at the valve sites on the north and south sides of the Straits crossing. For this reason, this threat is characterized as a Secondary Threat, and failure probability estimates for this threat have not been generated.

2.4.1.1.1.4.2.8 Time-dependent Threat due to Mechanical Damage

As highlighted in Section 2.4.1.1.1.3.9, significant mechanical damage, such as dents and gouges caused by installation damage or external interference that does not result in immediate failure, may, if it goes undetected, become more severe with the passage of time, such that it eventually causes a leak or rupture.

A review of Enbridge's 2013 MFL inspection and 2016 geopig inspection data showed no evidence of resident damage, however it is feasible that sub-critical damage could occur in the future as a result of external interference (most particularly, accidental damage due to inadvertent anchor deployment and drag).

The scenarios that might result in pipeline damage from this form of external interference make it such that it is almost impossible to foresee a circumstance whereby a serious incident of this nature could go both un-detected and un-reported. For this reason, this threat is characterized as a Secondary Threat, and failure probability estimates for this threat have not been generated.

2.4.1.1.1.4.2.9 Activation of Resident Damage from Pressure-Cycle-Induced Fatigue

As outlined in Section 2.4.1.1.1.3.12, this threat involves the role that pressure-cycle-induced fatigue might play in growing sub-critical defects associated with other threats to failure. Sub-critical defects that do not experience growth in service are considered to be stable defects that have a factor of safety established through post-installation hydrostatic testing. The degree to which fatigue can contribute to the growth of sub-critical defects is a function of the magnitude and frequency of individual pressure cycles that exist within the operating pressure spectrum of a pipeline. An analysis of the pressure spectra associated with the operating conditions of the Straits Crossing pipelines was completed to assess the severity of those pressure cycles, and their potential to contribute to the growth of sub-critical defects by means of fatigue mechanisms. That analysis found that the pressure profile for the Straits Crossing segments is classified as “Light”, meaning that the operating pressure spectrum that is characteristic of the Straits Crossing is not associated with pipelines that would experience failures due to activation of sub-critical defects by pressure-induced fatigue. For this reason, this threat is characterized as a Secondary Threat, and failure probability estimates for this threat have not been generated.

2.4.1.1.2 Probability Analysis

The approach, analysis and results of the probability analysis for all Principal Threats, and where applicable, for Secondary Threats are presented in this Section.

2.4.1.1.2.1 Principal Threats

As presented in Section 2.4.1.1.1.4.1, the Principal Threats for the Enbridge Line 5 Straits Crossing segments are:

- immediate failure due to mechanical damage;
- weather and outside force; and,
- incorrect operations

The approach used for deriving estimates of failure probability for each of the above threats are presented below, along with the analysis and results.

2.4.1.1.2.1.1 Immediate Failure Due to Mechanical Damage

In offshore pipelines, the greatest threat associated with mechanical damage is shipping activity, such as dropped objects (principally a concern only in the vicinity of production platforms), trawl board damage (confined to ocean environments where bottom trawling is used), or inadvertent anchor deployment and dragging while ships are underway. While the 20-in. Straits Crossing segments are not located in an area where production platforms exist or where bottom trawling occurs, they do lie below a busy shipping channel, and are therefore vulnerable to anchor interaction.

2.4.1.1.2.1.1.1 Approach

In response to an increased frequency of incidents and the resulting heightened focus on the part of pipeline owners and operators, a standardized approach has been developed to facilitate the completion of risk assessments in pipeline segments that are exposed to inadvertent deployment and drag of anchors (see Appendix E in *DNV Report 2009-1115* in Reference [71]). The approach constitutes a basis for estimating the annual probability of a pipeline failure associated with this scenario, as a function of the following factors:

- Number, and size distribution of ship crossings per unit time
- Water depth (relative to anchor chain length)
- Size of pipeline, and,
- Pipeline protection (depth of burial, use of armoring material)

The scenario leading to the inadvertent deployment and dragging of an anchor is outlined in Section 2.4.1.1.1.3.8. Three potential outcomes are considered as part of the development of that scenario:

- Outcome 1: Drop discovered within 1 km, and actions are taken. Anchor does not get seated, and reaches a maximum penetration depth corresponding to the perpendicular offset distance between the fluke and shank (75% of all accidental deployment occurrences; $2.0x10^{-08}$ per ship crossing);
- Outcome 2: Anchor seats within 1 km and attains maximum penetration depth (6.25% of all accidental deployment occurrences; $1.7x10^{-09}$ per ship crossing)
- Outcome 3: Anchor does not get seated, and is dragged for a greater distance, with maximum penetration depth corresponding to the perpendicular offset distance between the fluke and the shank (18.75% of all accidental deployment occurrences; $1.7x10^{-07}$ per ship crossing)

Assuming that parameters related to anchor size and chain length enable hooking, all three outcomes above may result in pipeline hooking. However, the first two outcomes are limited to relatively short distances, while the third outcome is more likely to cause damage to a pipeline due to the longer dragging distance.

In the assessment of the potential for a dragged anchor to cause damage to a pipeline, a number of factors are evaluated as a function of ship displacement (shipping class), including:

- Water depth related to anchor chain length
- Projected fluke length
- Anchor penetration depth
- Applied load forces from anchor, related to:
  - Anchor chain break load
  - Force and energy from ship in motion

The above damage criteria are then compared against pipeline resistance, which is evaluated as a function of:

- Pipeline size
- Type of pipeline installation (exposed, fully-embedded, or trenched)
- Soil type

In order for a pipeline to be hooked by a dragged anchor, three conditions must be met:

1. The water depth must be shallow enough to allow the anchor to be dragged along the lakebed given anchor chain lengths that are associated with the class of shipping that is in the area;
2. The pipeline must be small enough to be hooked by the anchors associated with the class of shipping in the area; and,
3. The pipeline must be buried at a depth that is shallow enough for interaction with an anchor to occur

With respect to Condition 1, an assumption is adopted that if the chain length associated with a class of shipping is longer than the water depth, anchors from that shipping class have the potential to reach the lakebed. This represents a conservative assumption, since it would be expected that an anchor that is dropped from a ship under way would not hang vertically from the hawse, but would rather be dragged some distance astern.

With respect to Condition 2, an assumption is adopted that if, for a given class of shipping, the perpendicular offset between the anchor fluke and the shank is at least half the pipe diameter, the pipeline has the potential to get hooked by anchors associated with that shipping class. Anchors from shipping classes where this condition is not met are assumed to be pulled across the pipeline without hooking.

With respect to Condition 3, only Outcome 2 involves anchors dragged at maximum penetration depth, which in turn, is established as a function of shipping class and soil type. For Outcomes 1 and 3, the flukes are assumed to penetrate only to the maximum fluke / shank perpendicular offset distance, which in turn, is determined as function of shipping class. For all three Outcomes, however, the type of pipeline installation (exposed, fully-embedded or trenched), and the depth of burial is important in determining whether the pipeline can get hooked by a dragged anchor.

Once the potential for hooking has been established, the analysis considers the force from the retarding ship, which is estimated through relationships between kinetic energy and force applied through the distance required to bring the ship to a stop. This force is assessed against the breaking strength of the chain and the limit state loads of the pipeline.

Two pipeline limit states are considered; the limit state associated with maximum strain capacity, and a limit state associated with critical dent size. The maximum strain capacities of pipelines were determined for a range of pipe sizes based on finite element analysis. Similarly, the loads associated with critical dents in a range of pipe sizes were determined by means of a dent limit state model. In the anchor interaction analysis, failure is determined if either the strain or dent limit is exceeded.

2.4.1.1.2.1.1.2 Analysis

Vessel Transit Frequency Distribution

Key to the analysis of anchor interaction studies is knowledge of the frequency distribution of ship crossings, by shipping class. In order to determine this, a Nationwide Automatic Identification System (NAIS) Historical Data Feed Request was submitted to the United States Coast Guard Navigation Center. NAIS vessel traffic data are collected from a network of VHF receiver sites located throughout the navigable waters of the United States, and AIS receivers provide coverage through the Straits. The NAIS system is designed to collect safety and security data from AIS-equipped vessels, including identification and classification of vessels.

NAIS data was obtained and analyzed for the years 2014, 2015 and 2016. For each recorded vessel transit, Maritime Mobile Service Identity (MMSI) information was obtained and cross-referenced to ship displacement. In this way, the average number of transits through the Straits of ships displacing more than a critical value was determined.

Feasibility of Anchor Interaction

For a given vessel class, in order for anchor interaction with a pipeline to occur, two conditions must exist:

1. The water depth must be no deeper than the anchor chain length; and,
2. The projected fluke length of the anchor must be at least as great as one-half the pipe diameter.

Tabulated values of anchor chain length and anchor projected fluke length by vessel class are provided in tables E.1 and E.2 of Appendix E in the *DNV Report 2009-1115* (see Reference [71]), and this information is summarized below.

Table 2-7: Anchor and Chain Dimensions by Vessel Class (DNV Report 2009-1115) [71]

Vessel Class	Displacement (tonnes)	GRT from	GRT to	Anchor Chain Length (m)	Anchor Mass (kg)	Anchor Projected Fluke Length (m)
I	1500	100	499	179	900	0.6
II	3600	500	1599	207	1440	0.6
III	10000	1600	9999	248	3060	0.9
IV	45000	10000	59999	317	8700	1.3
V	175000	60000	99999	372	17800	1.6
VI	350000	100000	-	385	26000	1.9

At the location of the existing Straits Crossings, the deepest water depth is 249 ft. (76 m). Also, the half-pipe-diameter dimension of the Straits Crossing Segments is 10 in. (0.254 m). Based on these values, it can be seen that the anchor chain lengths and projected fluke lengths for anchors in all vessel classes are such that they permit anchor hooking of the 20-in. Straits Crossing segments. Because the existing Straits Crossing segments are located on top of lakebed, any deployed and dragged anchor from any vessel class is assumed to hook the pipeline, regardless of scenario (Outcome 1, 2 or 3).

Overstrain Analysis

The tabulated strain limit state values provided in DNV Report 2009-1115 indicates that the force required to reach the strain limit in 20-in. diameter pipe ranges from 700 kN (for a fully-embedded pipeline in soft soil conditions) to 2,260 kN (for exposed pipe in hard soil conditions). With respect to installation conditions, the guidance provided is exposed pipelines in many cases are less vulnerable when hooked by anchors than embedded or trenched ones. This is due to the increased constraint associated with burial, resulting in more localized bending than would be incurred by a pipe that is not embedded and subject to high soil resistance. In the case of the 20-in. Line 5 crossings of the Straits, the pipeline lies on top of lake bottom through the shipping channel, yet at the same time pipeline screw anchors have been employed, which may act to offer constraint conditions similar to embedded pipe. As the condition of the lakebed has been described as varying between sandy and clay, the pipeline may have a critical force closer to 700 kN (corresponding to soft soil conditions), although a value of 2,260 kN (corresponding to hard soil conditions) will also be investigated to assess a possible lower-bound estimate of failure frequency.

Dent Analysis

The tabulated dent limit state values provided in DNV Report 2009-1115 indicates that the force required to cause a failure due to denting in 20-in. diameter pipe is 2,240 kN.

Failure Force Analysis

From the results of the overstrain and dent analyses, the limiting factor for failure in 20-in. pipe ranges from 700 kN (over-strain in pipe in soft soil conditions constrained by screw anchors such that it behaves like a fully-embedded pipeline) to 2,240 kN (dent).

An analysis of the chain break load data provided in DNV Report 2009-1115 indicated that ships displacing more than 2,029 tonnes reflect the upper-bound failure frequency associated with a critical force of 700 kN, and ships displacing more than 24,773 tonnes reflect the lower-bound failure frequency associated with a critical force of 2,240 kN.

Failure Probability Analysis

The lower-bound annual failure probability was determined by counting the number of ship crossings per year through the Straits that have displacements ≥24,773 tonnes (27,308 tons) and multiplying by the anchor/pipe interaction frequency of $1.9\text{x}10^{-07}$ per ship crossing (reflecting the frequency of Outcomes 1, 2 and 3). The upper-bound annual failure probability was determined by counting per year through the Straits that have displacements ≥2,029 tonnes (2,237 tons) and multiplying by the anchor/pipe interaction frequency of $1.9\text{x}10^{-07}$ per ship crossing.

Results

An analysis of the NAIS data indicated that over the years 2014 – 2016, inclusive, the number of vessel transits for ships displacing 24,773 tonnes (27,308 tons) or more ranged from 1,155 to 1,457, averaging 1,319. The number of vessel transits for ships displacing 2,029 tonnes (2,237 tons) or more ranged from 1,627 to 1,966, averaging 1,807. Therefore, the average annual failure probability was determined to range between 2.506×10^{-04} and 3.433×10^{-04}. A failure of only one of the two pipelines was assumed. This is because the combined forces associated with dragging both an anchor and a pipeline will affect both speed and maneuvering ability of the ship sufficiently to alert the pilot of a problem, enabling emergency response measures to be enacted before the second pipeline becomes hooked and dragged to failure. Furthermore, it is likely that the presence of a pipeline between the anchor fluke and shank will preclude the potential for a second pipeline to become lodged within that same space.

The analysis illustrated that there is little difference between the lower and upper-bound estimates of annual failure probability. Nevertheless, the upper-bound value of 3.433×10^{-04} will be selected for reporting purposes to reflect the constraint conditions associated with the use of screw anchors. As indicated in Section 2.4.1.1.1.4.1.1, for the purposes of associating failures attributed to anchor interaction with consequences in the determination of risk, the failure mechanism that has been assigned to this threat is full-bore rupture.

2.4.1.1.2.1.2 Weather and Outside Force – Vortex Induced Vibration

The evaluation of threat attributes associated with the threat of weather and outside forces (Section 2.4.1.1.1) indicated that the Straits Crossing segments are potentially vulnerable to fatigue caused by vortex-induced vibration at span locations, resulting from near-lake-bottom water currents. Depending on pipeline design attributes and span lengths, even moderate currents can induce vortex shedding, alternately at the top and bottom of the pipeline, at a rate determined by the velocity of water flowing around the pipe. Each time a vortex sheds, a force is generated, causing an oscillatory multi-mode vibration. This vortex-induced vibration can give rise to fatigue damage and failure of submarine pipeline spans.

2.4.1.1.2.1.2.1 Approach

Key to the analysis of the potential for fatigue failure resulting from vortex-induced vibration is a knowledge of pipeline design and material property parameters, span length, and water current velocity. Once these parameters are known, an amplitude response model can then be used to model vibration and stress response associated with vortex-induced resonance. A fatigue analysis of the output of the amplitude response model may then be used to predict fatigue life of the pipeline.

By expressing the variables of current velocity and span length as random variables, it was possible to perform multiple resampling simulations of the amplitude response / fatigue analysis by employing Monte Carlo analysis techniques in order to determine the probability that the fatigue life of the pipeline would be exceeded for each of a series of time periods. In this analysis, the probability of exceedance of the fatigue life over a specified time period corresponds to probability of failure due to vortex-induced vibration during that time period. This analysis is somewhat conservative because it uses upper-bound current velocity values along the lengths of both the East and West Straits crossing segments.

Current Velocity

Acoustic doppler current profiler (ADCP) buoys deployed at three locations within the Straits employ sound waves to measure the strength and direction of currents at 1-m intervals from the surface to the lake bottom. The data generated from these buoys were used to calibrate the hydrodynamic model used for modeling spill behavior (see Attachment 2 in Appendix S). Current velocity varies both with geographic position as well as time through the Straits. Because the ADCP buoys are not positioned at a high-enough density or at positions corresponding with both the East and West Straits Crossing pipeline segments, sole reliance on the ADCP data would not be sufficient to ensure that current velocity values used in the analysis were appropriately conservative or representative of currents in the immediate vicinity of the pipeline segments. Therefore, it was decided to use the output of the simulated bottom-layer current velocity values, generated using the hydrodynamic model (see Attachment 2 in Appendix S), which itself was calibrated using ADCP data. Accordingly, an extract of modeled hourly current velocity values over a one-year period was obtained from the bottom layer that corresponded to the position along both the East and West Straits crossing segments with the highest current velocity. These data extracts were used to fit probability density functions describing upper-bound temporal bottom-layer current velocity for both the East and West Straits Crossing segments. For the East segment, a Gamma distribution, having a Shape Parameter of 1.6861 and a Scale Parameter of 0.1051 was obtained, while for the West segment, a Lognormal distribution, having a mean of -2.1623 and a standard deviation of 0.7708 was obtained (see figures below[14]).

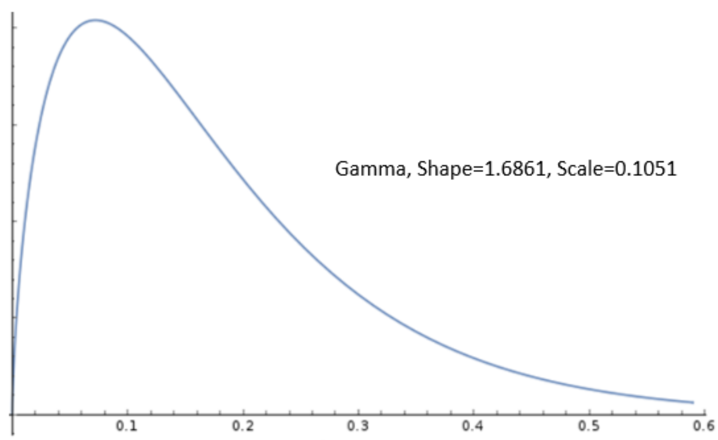


Figure 2-8: Upper-Bound Bottom Layer Current Velocity, East Segment

[14]Expressed in units of m/s.

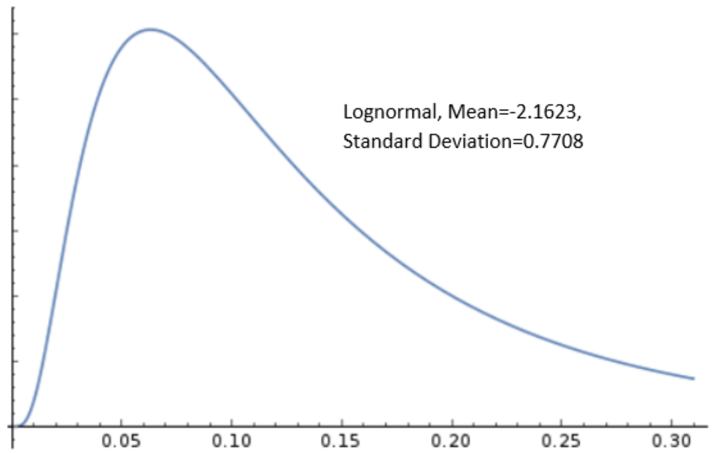


Figure 2-9: Upper-Bound Bottom Layer Current Velocity, West Segment

Span Length Distribution

Based on a review of information obtained from seven underwater inspections of the East and West segments spanning the years 2005 – 2016, it was observed that the lengths of individual spans change over time. [82] While the terms and conditions of the April 23, 1953 Straits of Mackinac Pipeline Easement limit allowable span length to 75 ft., and maintenance activities have been undertaken to maintain span lengths to less than that limit, span lengths have varied both below and above that limit over time. Therefore, for modeling purposes, it would be non-conservative to assume that span lengths will be limited to 75 ft. on a go-forward basis. Instead, the results of the seven inspections performed between 2005 – 2016 were used to generate separate span length distributions for each of the East and West segments. A total of 715 separate span length measurements were used to generate a span length distribution on the East segment, and 691 separate span length measurements were used to generate a span length distribution on the West segment. In both cases, Weibull distributions were found to provide the best fit to these data, as shown in the figures below[15].

[15]Expressed in units of ft.

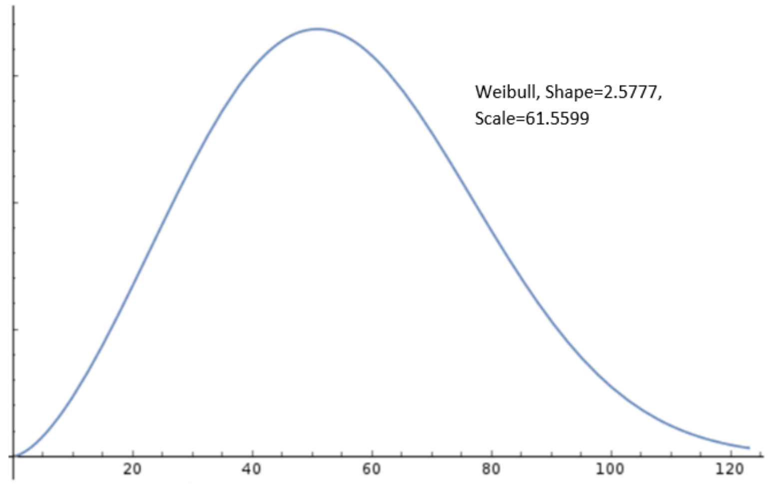


Figure 2-10: Span Length Distribution, East Segment

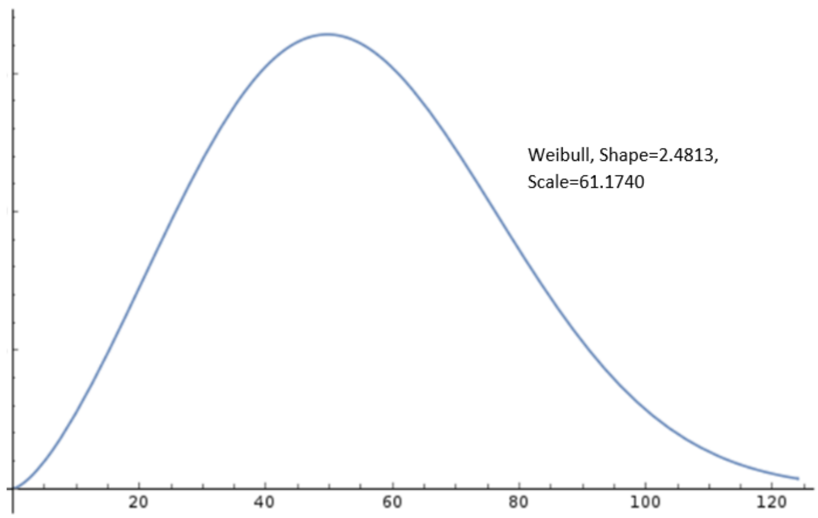


Figure 2-11: Span Length Distribution, West Segment

VIV Models and Remaining Life

An amplitude response model was used to predict the vibration behavior of pipeline spans subjected to vortex induced resonance. Amplitude response models are empirical models providing the maximum steady state vortex-induced vibration (VIV) amplitude response as a function of the basic hydrodynamic and structural parameters. The in-line and cross-flow response models described in DNV Recommended Practice DNV-RP-F105 [83] were used to characterize the vibration response behavior of the 20-in. diameter Straits pipeline segments, given the span length and water current velocity distributions described in the preceding sections. Under this approach, the in-line VIV induced stress range, S_{IL}, and the cross-flow induced stress range S_{CF} are determined as follows:

$$S_{IL} = 2 \cdot A_{IL} \cdot \frac{A_y}{D} \cdot \psi_{\alpha,IL} \cdot \gamma_s$$

Equation 2-3: In-Line VIV Stress Range

and,

$$S_{CF} = 2 \cdot A_{CF} \cdot \frac{A_z}{D} \cdot R_k \cdot \gamma_s$$

Equation 2-4: Cross-Flow Induced Stress Range

Where,

A_{IL},A_{CF}: Unit stress amplitude for in-line mode shape deflection, and cross-flow mode shape deflections, respectively (a function of pipe diameter, wall thickness, span length, and elastic modulus); and,

A_y/D, A_z/D: Normalized maximum in-line VIV response amplitude, and cross-flow VIV response amplitude, respectively (a function of current velocity, natural vibration frequency of pipeline span, and pipe diameter)

$\Psi_{\alpha,IL}$, R_k, γ_s: Correction factors, safety factors, reduction factors.

Once determined, the VIV induced stress range and VIV induced vibration frequency were used to determine fatigue life, based on the fatigue curve approach of API Recommended Practice 579 [84] Under this approach, the permissible number of fatigue cycles, *N*, is determined as:

$$N = A \cdot f_t \cdot f_c \left[\left(\frac{2.09 \times 10^5}{E_y} \right) \sigma_r \right]^m$$

Equation 2-5: Fatigue Equation

Where,

A = Fatigue data constant,

f_t = Thickness correction factor,

f_c = Environmental correction factor

E_y = Modulus of elasticity

σ_r = Stress range

m = Fatigue exponent

In the above relationship, the values for fatigue data constant and fatigue exponent were selected for full-penetration butt-welded connections subjected to non-destructive examination, consistent with the weld design and inspection characteristics of the Straits Crossing pipeline segments. An Environmental correction factor was obtained from BS7910 [85] from the ratio of Paris Law Constants in non-aggressive environments vs marine environments, to reflect the fact that fatigue life is lower in corrosive environments.

Under the API 579 fatigue life approach described above, the permissible number of fatigue cycles, *N*, is defined as the number of cycles that corresponds to a survival probability of 98% (i.e., a failure probability of 2%). Therefore, the probability of failure over a defined period of time was determined by multiplying the probability of incurring the permissible number of fatigue cycles within that time period, and multiplying by 2%.

Probability Calculations

The probability of failure due to vortex-induced vibration was determined for each of a number of assessment periods (representing the number of years of service) by employing multiple resampling iterations in a Monte Carlo analysis. In each simulation, a value of water current velocity and a value of span length were randomly selected from the probability density functions used to characterize the distributions for those two variables, and the number of allowable fatigue cycles was determined. This value was then converted to fatigue life (years) by accounting for the frequency of vibration. This was undertaken for both in-line amplitude response and cross-flow amplitude response. For each response model, the probability of failure for each evaluation period was determined as the fraction of simulations in which the service life within the evaluation period exceeded allowable fatigue life. The combined probability of failure within each evaluation period was determined as the probability of exceedance based on in-line amplitude response *or* the probability of exceedance based on the cross-flow amplitude response. A total of 100,000,000 simulations were conducted on both the East and West segments, providing a probability resolution of $1x10^{-08}$.

Results

The results of the analysis are provided for each of the East and West segments in the Table 2-8. This table represents the probability of having a failure in either the East or West segments (individually, as well as combined) within a given period of operation, ranging from the years 2018 through to 2053. The combined failure probability for East and West segments is calculated as the statistical *or* function of the two probabilities (i.e., $P_{EastORWest} = 1-[(1-P_{East})*(1-P_{West})]$).

Table 2-8: Vortex-Induced Vibration Fatigue Failure Probability

Period of Operation, Years (Year)	Probability of Failure within Time Span		
	East Segment	West Segment	East or West Segments
65 (2018)	$1.84x10^{-06}$	$1.23x10^{-05}$	$1.42x10^{-05}$
70 (2023)	$1.92x10^{-06}$	$1.26x10^{-05}$	$1.45x10^{-05}$
75 (2028)	$2.00x10^{-06}$	$1.28x10^{-05}$	$1.48x10^{-05}$
80 (2033)	$2.08x10^{-06}$	$1.30x10^{-05}$	$1.51x10^{-05}$
85 (2038)	$2.14x10^{-06}$	$1.32x10^{-05}$	$1.53x10^{-05}$
90 (2043)	$2.22x10^{-06}$	$1.34x10^{-05}$	$1.56x10^{-05}$
95 (2048)	$2.28x10^{-06}$	$1.36x10^{-05}$	$1.58x10^{-05}$
100 (2053)	$2.34x10^{-06}$	$1.37x10^{-05}$	$1.61x10^{-05}$

As indicated in Section 2.4.1.1.1.4.1.2, for the purposes of associating failures attributed to outside force with consequences in the determination of risk, the failure mechanism that has been assigned to this threat is full-bore rupture.

In the Monte Carlo simulation of vortex-induced vibration fatigue life, it was noted that unless the extremes of both the water velocity and span length distributions were selected as the basis of a simulation, the calculated fatigue life would be well over 100 years. In order for a simulation to return a fatigue life within a period of operation of less than 100 years, not only would extremes of both the water velocity and span length distributions need to be selected, but those values of water velocity and span length would need to be held at extreme levels for the full period of operation. Based on a review of ADCP buoy data, it seems unlikely that current velocity is likely to hold constant at an extreme level for extended periods of time; rather, current velocity magnitudes appear to fluctuate with time. Similarly, given the underwater inspections that have occurred on a biennial basis since 2010, it is unlikely that an individual span will be maintained at an extreme value, well in excess of the mandated 75 ft. limit for the full duration of pipeline operation. For this reason, the failure probability values reported above should be taken as conservative.

2.4.1.1.2.1.3 Weather and Outside Force – Spanning Stress Analysis

A spanned section of pipeline is exposed to a biaxial stress state, owing to bending stresses (both gravity-induced and drag-induced), axial stresses (thermal stress and Poisson’s operating stress), and operational hoop stress. This state of biaxiality can be resolved as a maximum combined effective stress using the Von Mises criterion.

In a dynamic environment in which the variables that control the calculation of maximum combined effective stress (in particular, water currents, span lengths, and gap ratios) change with time, the maximum combined effective stress at any given location has the potential to change over time, in a repetitive manner. Therefore, for the purposes of the analysis, the probability of failure was defined as the probability of exceedance of the yield point of the material (as opposed to plastic collapse), recognizing that the potential for plasticity creates the potential for plastic fatigue, which can progress to failure after relatively few cycles.

2.4.1.1.2.1.3.1 Stress Analysis

Pipeline spanning creates bending stresses associated with deflection due to the combined effects of gravity and water current-induced drag. These bending stresses are combined with axial stresses arising from other conditions, such as temperature differential and operational Poisson’s stress to arrive at maximum longitudinal stress. In order to address biaxial stress, the longitudinal stress is combined with hoop operating stress to provide the maximum combined effective stress.

The above stress relationships are described below.

Spanning Stresses Due to Gravity

The maximum bending stress due the weight of pipe over a span is:

$$\sigma_{b,g}^{\max} = \frac{M_{\max}}{I}\cdot\frac{D}{2} = \frac{\left(\dfrac{wl^2}{10}\right)}{\dfrac{\pi}{64}\left[D^4-(D-2t)^4\right]}\cdot\frac{D}{2}$$

Equation 2-6: Maximum Bending Stress Due to Pipe Weight [86, p. 7]

Where,

$\sigma_{b,g}^{max}$ = Maximum bending stress due to weight of pipe (moderate soil conditions at span ends)

M_{max} = Maximum bending moment

I = Moment of Inertia

D = Pipe diameter

w = Weight of pipe per unit length (determined as the net sum of weight of steel pipe, weight of product, weight of mussels [87], and buoyancy forces).

l = span length

Spanning Stresses Due to Drag

The drag force per unit length (F_D/L) acting on a pipeline span exposed to water currents is determined as: [88, p. 33]

$$F_D = \frac{1}{2} \cdot C_D \cdot \rho \cdot D \cdot U^2$$

Equation 2-7: Drag Force Due to Water Current

Where,

C_D = Drag coefficient

ρ = Water density

D = Pipeline diameter (accounting for increased diameter due to mussel encrustation)

U = Water velocity

In the above relationship, and in order to support stochastic modeling, water velocity was expressed in terms of probability density functions for both the East and West segments (derived as described in Section 2.4.1.1.2.1.2).

The drag coefficient was determined as: [83, p. 29]

$$C_D = C_D^o(k/D) \cdot \psi_{KC,\alpha}^{CD} \cdot \psi_{proxi}^{CD} \cdot \psi_{trench}^{CD} \cdot \psi_{VIV}^{CD}$$

Equation 2-8: Drag Coefficient Equation

Where,

$C_D^o(k/D)$ = the basic drag coefficient for steady flow. Per the guidance of DNV F-105, a value of 1.05 was used, corresponding with rough surfaces

$\psi_{KC,\alpha}^{CD}$ = the Keulegan-Carpenter correction factor. Per DNV F-105, a value of 1.0 was used, corresponding to negligible wave-induced flow velocity

ψ_{proxi}^{CD} = a correction factor accounting for lakebed proximity, and is a function of gap ratio, e/D. This was characterized as a random variable derived by fitting distributions for both the East and West Segments, based on inspection data. [89] For the East segment, a Weibull distribution, having a Shape Parameter of 1.561202 and a Scale Parameter of 0.778966 was derived, and for the West Segment, a Weibull distribution, having a Shape Parameter of 2.213108 and a Scale Parameter of 0.893032 was derived.

ψ_{trench}^{CD} = a correction factor accounting for the effect of a pipe in a trench. In accordance with the guidance of DNV F-105, where the pipeline is un-trenched, a value of 1.0 is used

ψ_{VIV}^{CD} = an amplification factor due to cross-flow vibrations. This is derived as a function of the cross-flow vortex-induced vibration amplitude, A_Z/D, which in turn, is a function of current velocity, natural vibration frequency of the span, and diameter. For the purposes of this calculation, both the linear weight of mussels, and the added thickness of mussels were used. [87] Because the natural vibration frequency of the span is in part a function of span length, this term was expressed as a random variable described by probability density functions as described in Section 2.4.1.1.2.1.2.

The drag force per unit length was used to derive the maximum bending stress due to drag forces, $\sigma_{b,FD}^{max}$, which acts normal to the maximum bending stress due to gravity:

$$\sigma_{b,FD}^{\max} = \frac{M_{\max}}{I} \cdot \frac{D}{2} = \frac{\left(\frac{F_D \cdot l^2}{10}\right)}{\frac{\pi}{64}\left[D^4 - (D-2t)^4\right]} \cdot \frac{D}{2}$$

Equation 2-9: Maximum Bending Stress Due to Drag Force

Combined Bending Stress

The sum of the bending stresses in the vertical ($\sigma_{b,V}$, bending due to gravitational forces) and horizontal ($\sigma_{b,H}$, bending due to drag forces) planes was determined as [86, p. 6]:

$$\sigma_{b,\max} = \sqrt{\sigma_V{}^2 + \sigma_H{}^2}$$

Equation 2-10: Sum of Vertical and Horizontal Bending Stresses

Combined Longitudinal Stress

Combined longitudinal tensile stress ($\sigma_{L,Comb}$) was then determined as [86, p. 8]:

$$\sigma_{L,Comb} = \sigma_{b,\max} + \sigma_{axial,Poisson} + \sigma_{\Delta T}$$

Equation 2-11: Combined Longitudinal Stress

Where,

$\sigma_{axial,Poisson}$ = Poisson's axial stress due to operating pressure

$\sigma_{\Delta T}$ = Longitudinal stress due to temperature differential

Poisson's axial stress due to operating pressure was determined as:

$$\sigma_{Axial,Poisson} = \frac{P_{Net} \cdot D \cdot \nu}{2 \cdot t}$$

Equation 2-12: Axial Poisson's Stress Due to Operating Pressure

Where,

P_{Net} = Net operating pressure (internal pressure – ambient pressure)

D = Diameter

t = Wall thickness

v = Poisson's ratio (= 0.3 for steel)

Axial stresses due to temperature differential is determined as:

$$\sigma_{\Delta T} = -\alpha \cdot E \cdot (T_o - T_i)$$

Equation 2-13: Axial Stress Due to Temperature Differential

Where,

α = Thermal Expansion Coefficient

E = Young's modulus

(T_o-T_i) = Temperature differential between installation and operation. A temperature differential of 10°C (18°F) was assumed, derived from bottom-layer water temperature data. [90]

Hoop Stress

To account for the biaxial stress state of the pipeline, hoop stress was determined as:

$$\sigma_h = \frac{P_{Net} \cdot D}{2 \cdot t}$$

Equation 2-14: Operating Hoop Stress

Maximum Combined Effective Stress

The Von Mises maximum combined effective stress (σ_e) was then determined as [86, p. 8]:

$$\sigma_e = \sqrt{\sigma_h^{\;2} + \sigma_{L,Comb}^{\;\;2} - \sigma_h \cdot \sigma_{L,Comb}}$$

Equation 2-15: Von Mises Maximum Combined Effective Stress

2.4.1.1.2.1.3.2 Probability of Failure

Multiple stochastic simulations of the above stress calculations were performed in a Monte Carlo analysis, with each simulation using random variables of span length, water current velocity, and gap ratio derived from the probability density functions for those variables described in the preceding Section. In each simulation, the Von Mises maximum combined effective stress was compared against the yield stress of the material.

For the purposes of the analysis, the probability of failure was defined as the fraction of simulations in which the Von Mises maximum combined effective stress exceeded yield stress. This condition was selected as a failure criterion because although there is ample strain capacity beyond yield (and therefore, failure does not occur when the maximum combined effective stress reaches yield stress), it defines the onset of plasticity. In a dynamic environment, characterized by changing water currents, span lengths and gap ratios, there is potential for the maximum combined effective stress to vary with time in a repetitive manner, as the variables that control the stresses vary over time. Under such conditions, the potential for plasticity creates the potential for plastic fatigue, under which conditions, progression to failure can occur after relatively few cycles.

Because water depth and product density affects the biaxial stress state of a spanned pipeline, six different scenarios were evaluated for each crossing segment, corresponding with two different water depths (the minimum and maximum depths along the untrenched portion of the segment), and three different product density values, encompassing the full range of densities. For each of the six scenarios evaluated per segment, a total of 100,000,000 Monte Carlo simulations were conducted, providing a resolution of $1.0x10^{-08}$.

From this analysis, the failure probability was determined to be below the resolution of the analysis – i.e., $<1.0x10^{-08}$.

2.4.1.1.2.1.4 Incorrect Operations

Numerous pipeline investigation analyses have shown that regardless of the direct cause, some element of incorrect operations, such as procedural, process, implementation or training factors invariably plays a role in the root causes of pipeline failure. Because it is often not possible to foresee in advance what sequence of events and breakdown in management systems and operating practices might lead to failure, there is no reliability-basis for predicting failure probability associated with this threat, and so incident data must be used to provide guidance on failure likelihood.

2.4.1.1.2.1.4.1 Approach

A comprehensive report on failure statistics by cause for offshore hazardous liquid pipelines is maintained by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) [2]. This database contains pipeline failure statistics for more than 5,100 mi. (8,208 km) of offshore hazardous liquids pipeline infrastructure in the US. A review of this database was completed for the years 2002 through 2016, inclusive, representing 76,856 mi.-y of offshore operating history. A filter was applied to exclude incidents associated with offshore platforms and wellhead flow lines. Within that record there was only one failure attributed to incorrect operations.

2.4.1.1.2.1.4.2 Results

Based on an analysis of industry incident data, the failure rate associated with incorrect operations in offshore hazardous liquids pipelines was determined to be $1.301x10^{-05}$ failures/mi.-y. Over the 7.74 mi. (12.4 km) of pipeline covered by the East and West

Straits Crossing segments, the annual failure probability associated with this threat was determined to be 1.007x10^{-04}.

2.4.1.2 Combined-Threat Failure Probability

Combined-threat failure probability is not used in the calculation of risk, since it represents combined (leak and rupture) failure mechanisms, and cannot therefore be associated with a specific consequence for risk calculation purposes. Nevertheless, combined-threat failure probability is reported in this Section for illustration purposes only.The combined annual probability of failure for the 20-in. Straits Crossing segments is determined as the statistical OR calculation of the failure probabilities associated with the principal threats:

$$P_{Comb} = 1 - \left[(1 - P_{MD}) \times (1 - P_{VIV}) \times (1 - P_{Span}) \times (1 - P_{IO})\right]$$

Equation 2-16: Combined-Threat Failure Probability, Existing Straits Segments

Where,

P_{Comb} = Combined-threat annual failure probability for the existing straits segments

P_{MD} = Annual failure probability associated with the threat of immediate failure due to mechanical damage (Section 2.4.1.1.2.1.1)

P_{VIV} = Annual failure probability associated with the threat of vortex-induced vibration (Section 2.4.1.1.2.1.2)

P_{Span} = Annual failure probability associated with the threat of spanning (Section 2.4.1.1.2.1.3)

P_{IO} = Annual failure probability associated with the threat of incorrect operations (Section 2.4.1.1.2.1.4)

2.4.1.3 Results

The combined-threat annual failure probability for the existing straits segments was determined as a function of time, as presented below.

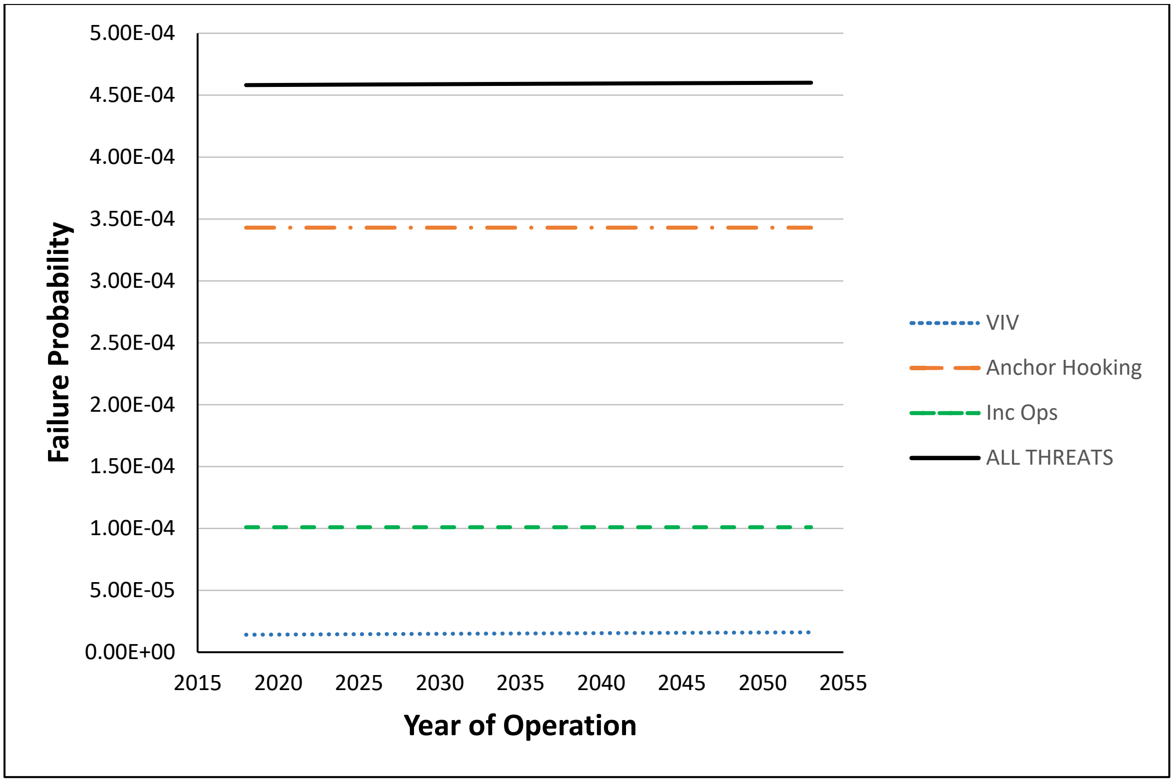


Figure 2-12: Failure Probability over Time

2.4.2 Spill Consequence Analysis

For the purposes of the environmental effects analysis, only releases of oil are considered, as NGLs (which are principally propane) do not persist in the environment. NGL releases are considered as part of the health and safety consequence analysis contained in sections 2.4.2.3, 2.4.2.4, 2.4.2.5.

2.4.2.1 Oil Spill Release Modeling

An oil outflow analysis was performed to estimate the amount of oil that could potentially spill into the Straits from a failure in one of the existing 20-in Line 5 Straits Crossing pipeline segments.

This section determines estimated release volumes of oil associated with the failure scenarios considered in the failure probability analysis (see Section 2.4.1). These release volumes are subsequently used as input to the oil spill simulation and analysis in Section 2.4.2.2.

2.4.2.1.1 Methodology

The outflow analysis employed an outflow volume calculation to determine the potential magnitude of product release corresponding to a pipeline failure.

The failure modes were determined based on the Principal Threats identified in Section 2.4.1. As outlined in that section, three Principal Threats were identified; Immediate Failure Due to Mechanical Damage, which addressed the threat of ship anchor interaction, Weather and Outside Forces, which is associated with spanning, and Incorrect Operations. For this alternative, two representative release sizes were selected that are related to those two threats. Because failure due to spanning and anchor interaction with a pipeline would typically be expected to result in an overload failure involving the cross-section of the pipeline, an FBR is assigned to those threats.

Failures attributed to Incorrect Operations, meanwhile, are related to improper operating and maintenance practices, and rarely result in full-bore ruptures. Instead, a hole size for Incorrect Operations was set at 75 mm (3 in.), based on the probability-weighted value derived from published hole size distributions for offshore pipelines [71, p. 40]

Dynamic Risk Outflow software (Version 0.97.0.4465) performed the outflow calculations. As described in Appendix N, the outflow calculation includes all four phases of a release:

1. pre-detection/troubleshooting
2. pump shutdown
3. valve closure
4. drainage.

2.4.2.1.2 Assumptions for Outflow Modeling

Release volume calculations were based on the following assumptions:

- Outflow from two hole sizes; 3-in (75 mm) diameter and full-bore rupture, representative of the failure mechanisms associated with the principal threats.
- Outflow from three release locations, representing a range of positions within the bathymetric profile.
- Detection, response and isolation times that are approximately 4 x longer than those that are specified by the performance standards of the leak detection and isolation equipment currently in place at the Straits Crossing segments.
- Full drain-down to the fullest extent possible, given the elevation profile and valve configuration associated with the Straits Crossing segments.

The outflow results do not take account of any response, intervention or any attenuation of release volumes.

The pipeline centerline, valve locations, and system information regarding leak detection and valve shutdown times were provided by Enbridge as part of a series of information requests [91] [92] [93] [94], as well as within the Operational Reliability Plan for Line 5 and the Straits of Mackinac Crossing [95]. The product density and viscosity values used correspond to the type of oil which is most commonly transported by Line 5. While this information is considered commercially-sensitive, values were provided by Enbridge for use with this analysis. Similarly, the flow rate was based on the average annual flow rate for 2015 and 2016 (Q1 to Q3), as provided by Enbridge [96].

2.4.2.1.2.1 Leak Detection and Isolation Time

The monitoring and leak detection system employed on the Straits Crossing segments includes three separate systems:

- Pipeline controller monitoring of abnormal conditions, including pressure drop via SCADA.
- Computational Pipeline Monitoring (CPM) systems that include a real-time transient model and line balance calculations.
- Local low pressure shutdown logic system in Straits isolation valves.

The local low pressure logic system in the Straits isolation valves is designed to initiate a cascade shutdown of Line 5 and isolate the Straits segments upon detection of a low pressure condition. As outlined in Table 2-9, in the event of a rupture or a large leak, the system is designed to achieve full isolation within 3 minutes. Nevertheless, for outflow modeling purposes, an isolation time of 13.5 minutes was chosen for the rupture scenario, representing an isolation time that is in excess of 4 x system performance standards.

As outlined in Table 2-9, in the event of a 3-in (75 mm) hole at the positions modeled, the leak detection equipment currently present at the Straits Crossing is designed to detect the release within 5 minutes, and achieve full isolation within 8 minutes. Nevertheless, for outflow modeling purposes, an isolation time of 33.5 minutes was chosen for the 3-in (75 mm) hole scenario, representing an isolation time that is in excess of 4 x system performance standards.

In some circumstances, such as was the case in the Marshall Incident on Enbridge Line 6B, column separation (the creation of a vacuum within a segment of a pipeline) can create problems for leak detection and isolation equipment, resulting in the normalization of false alarms. While column separation is associated with high-elevation segments of a pipeline, the Straits Crossing segments represent the lowest elevation point along Line 5, and these segments are not prone to column separation. Therefore, the assumptions on leak detection and isolation time that were used for the purposes of outflow modeling, which represent isolation times that are in excess of 4 x the performance standards of the equipment present at that site, are considered appropriately conservative.

Table 2-9: Response Time Assumptions, 20-in. Straits Crossing Segments

	Equipment Design Standards				Values Assumed For Calculations			
Release Size	Detection & Response	Pump Shut-down	Valve Closure	Total Isolation Time	Detection & Response	Pump Shut-down	Valve Closure	Total Isolation Time
FBR	Immediate	Immediate	3 min	3 min	10 min	0.5 min.	3 min.	13.5 min.
3-in. (75 mm) Dia. Hole	5 min	Immediate	3 min	8 min	30 min.	0.5 min.	3 min.	33.5 min.

2.4.2.1.3 Results

Figure 2-13 presents the elevation profile of the 20-in. pipeline crossing of the Straits, with the release locations superimposed. The outflow volumes were calculated for each of the East and West pipeline segments along the shipping channel. Table 2-10 contains the results. The small difference in volume of the released product from the East and West pipelines can be attributed to a slight difference in elevation profile of each pipeline. Although the outflow volumes are only slightly different between the two segments, the larger of the two results (the East segment) was used as the basis of the oil spill simulation analysis.

Similarly, since the FBR simulation of the East segment produced larger outflow volumes, the leak simulation was conducted for the East segment only.

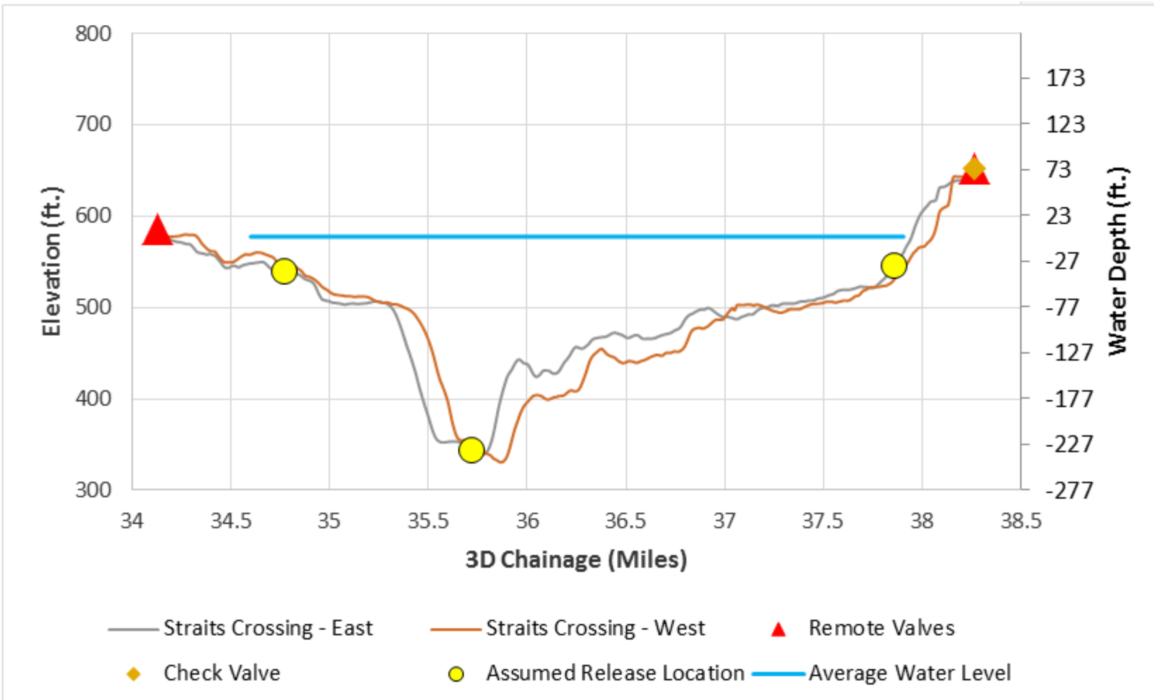


Figure 2-13: 20-in. Straits Crossing Segment Profiles and Simulated Release Location

Table 2-10: 20-in. Volume Outflow Results

Release Size	Pipeline	Principal Threat	Release Location	Released Volume (bbl)
FBR	East Straits crossing pipeline	Mechanical Damage Weather and Outside Forces	Shipping channel	2,629
	West Straits crossing pipeline			2,623
Leak/puncture (3-in. dia.)	East Straits crossing pipeline	Incorrect Operations	Near North Shore	2,902
Leak/puncture (3-in. dia.)	East Straits crossing pipeline		Near South Shore	4,527

As illustrated in Table 2-10, the largest outflow volumes are associated with 3-in. (75 mm) holes. This is attributed to the shallower water depth at these locations, which results in lower hydrostatic pressure, and greater *drain-up* of product, which, being lighter than water, rises to higher-elevation points within the isolated pipe section.

2.4.2.2 Oil Spill Simulation and Analysis

2.4.2.2.1 Oil Spill Simulation

The MIKE powered by DHI MIKE 21/3 Oil Spill (OS) model was used to simulate spills of the Canadian Sweet Blend in the Straits based on the results from the oil spill release modeling (see Section 2.4.2.1).

The MIKE 21/3 OS model was used in deterministic and stochastic modes to determine the range of possible water surface and shoreline oiling during an entire year. Based on analysis of typical weather patterns, with consideration of periods of time with significant ice coverage, the chosen production period was set from July 1, 2014 to June 30, 2015.

The spill is dependent on the hydrodynamic conditions, waves and winds prevalent at the time of the spill as well as the properties of the spilled oil. Whereas, the properties of the oil that may be spilled at the field can be given with some certainty based on the environmental conditions that affect the drift. Spreading and weathering of the spilled oil are dependent on the environmental conditions occurring at the time of the spill, and vary significantly over time. To accommodate this uncertainty, multiple oil spill simulations have been carried out over a one year period with temporal and spatial varying environmental conditions.

The temporal and spatial variations in the environmental conditions have been described using publicly available meteorological data, bathymetry (public and project-specific) and current measurements from different devices over the years. DHI created a detailed three-dimensional (3D) hydrodynamic model and a spectral wave model covering Lake Michigan and Lake Huron, with a higher resolution computational mesh for the areas in closer proximity to the Straits that are most likely affected by a spill in the Straits. A detailed description of the hydrodynamic and wave model set up, validation and chosen production periods is given in Attachment 2 (see Appendix S).

2.4.2.2.1.1 Study Limitations

The spill scenarios chosen represent a limited number of possible occurrences and it is recognized that the results could differ with different outflow volumes or spill locations. The objective of the study has been to establish realistic consequences of possible oil spill scenarios, and does not represent worst case scenarios.

Further, when referring to the results of the oil spill modeling, it is noted that the statistical maps combine the trajectories of many oil spill simulations and the maps do not reflect the risk of oil exposure for a single spill. It is also noted that the oil spill modeling carried out for this report is suitable for response planning and associated economic and environmental consequence assessment; however, it does not aim to provide oil spill trajectories for an actual response situation.

2.4.2.2.1.2 Methodology

DHI's MIKE 21/3 OSI model has been used to predict the spreading, drift and weathering of spilled oil under varying environmental conditions. The model is implemented in the highly flexible open equation solver, which is part of the MIKE ECOLab software. Oil is represented as Lagrangian particles drifting (being advected) with the surrounding water body and exposed to weathering processes. The drift of the individual particles is determined by the combined effects of current, wind and bed drag. The variation of current speed over the water depth is emulated by application of a drift profile, being a combination of a simulated current profile or traditional assumed bed shear profile (logarithmic) and wind acceleration of particles directly exposed to the wind.

Weathering processes cause the oil properties of each particle to change over time and with the ambient environmental conditions. A detailed description of the oil spill processes, oil weathering assumptions and related information is provided in Attachment 2 (see Appendix S).

An oil spill simulation using MIKE 21/3 OS describes the spreading, drift and weathering of a single spill taking place over a given period and for a number of days after the spill has stopped. For this study, a simulation length of 30 days has been chosen to allow the full development of the spill. As mentioned previously, the starting time of the simulation is random to avoid any bias in the drift trajectories.

From statistical analysis of the simulation results, predicted spill trajectory maps have been generated to depict the:

- Probability (risk) of a given area being exposed to spilled oil.
- Minimum time for the occurrence of spilled oil to reach a given area after the initial release of the oil.
- Maximum length of shoreline exposure (risk) and extent of exposure above a threshold.

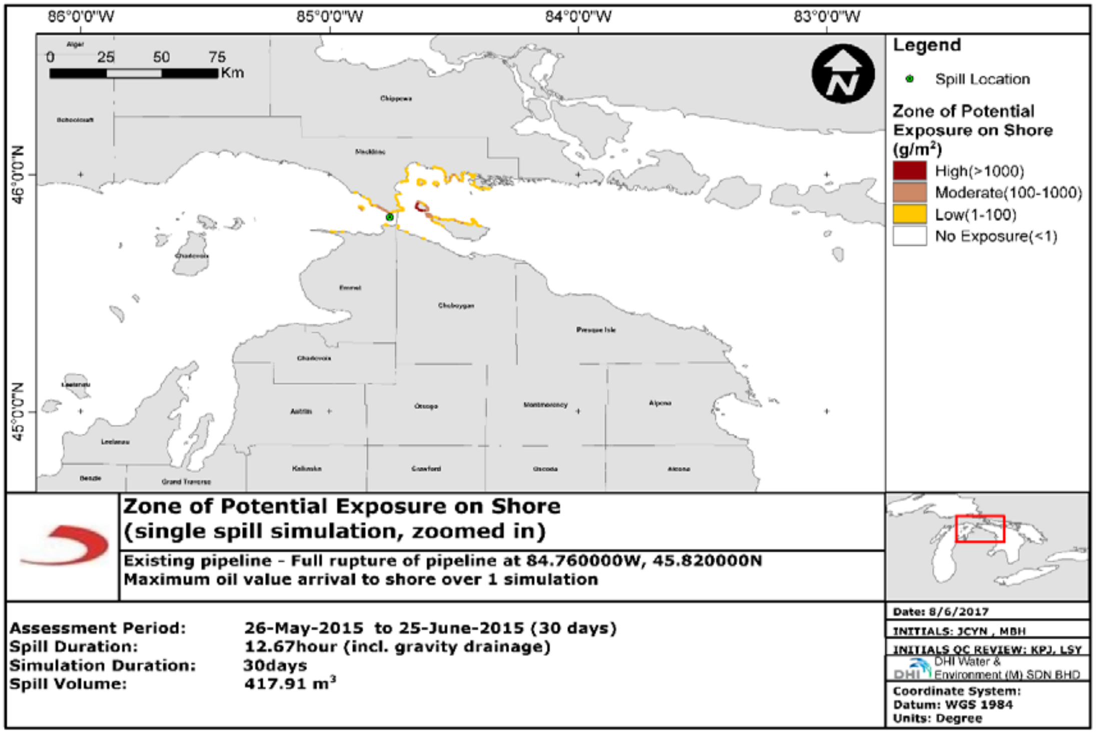
Three hypothetical spill scenarios representing pipeline failure have been considered for the existing 20-in. pipeline (see Table 2-11). The oil type is the same for all release scenarios.

Table 2-11: Spill Scenarios for Existing Straits Crossing Pipeline

Spill Scenario	Release Point (coordinates)	Total Outflow Volume bbl (m^3)	Spill Duration	Simulation Duration
Full rupture	Lat: 45.8200, Long: -84.7600	2,629 (417.9)	10 minutes detection/troubleshooting time + 30 seconds pump shutdown + 3 minutes valve closure + 5.83 hours drainage time	30 days
3-in. (75 mm) leak at northern shore	Lat: 45.8331, Long: -84.7547	2,902 (461.4)	30 min. detection/troubleshooting time + 30 s pump shutdown + 3 min. valve closure + 1 h drainage time	30 days
3-in. (75 mm) leak at southern shore	Lat: 45.7900, Long: -84.7711	4,527 (719.7)	30 min. detection/troubleshooting time + 30 s pump shutdown + 3 min. valve closure + 3.5 h drainage time	30 days

The results of the oil spill model are presented as probability maps of a spill occurring in water and the ZOE. Each map is composed from 120 single spill trajectories over one full year. In other words, the results do not present a single possible spill scenario but a distribution of possible spill trajectories over the year July 2014 to June 2015.

The results of one spill trajectory (started May 26, 2015, run for 30 days) are shown in Figure 2-14 and Figure 2-15, with the ZOE, the thickness of the oil slick and the arrival time to the shore being the main descriptors.



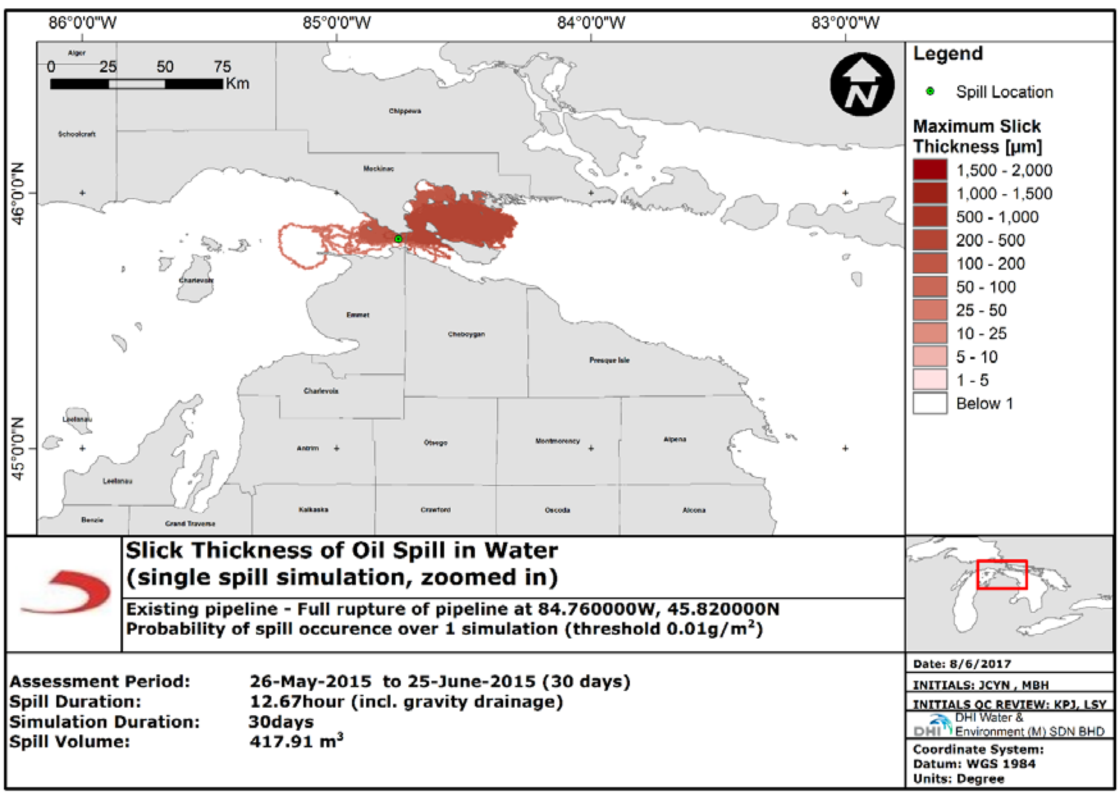


Figure 2-14: Zone of Exposure (top), Oil Slick Thickness (bottom), Arrival Time of Spill Trajectory on May 26, 2015

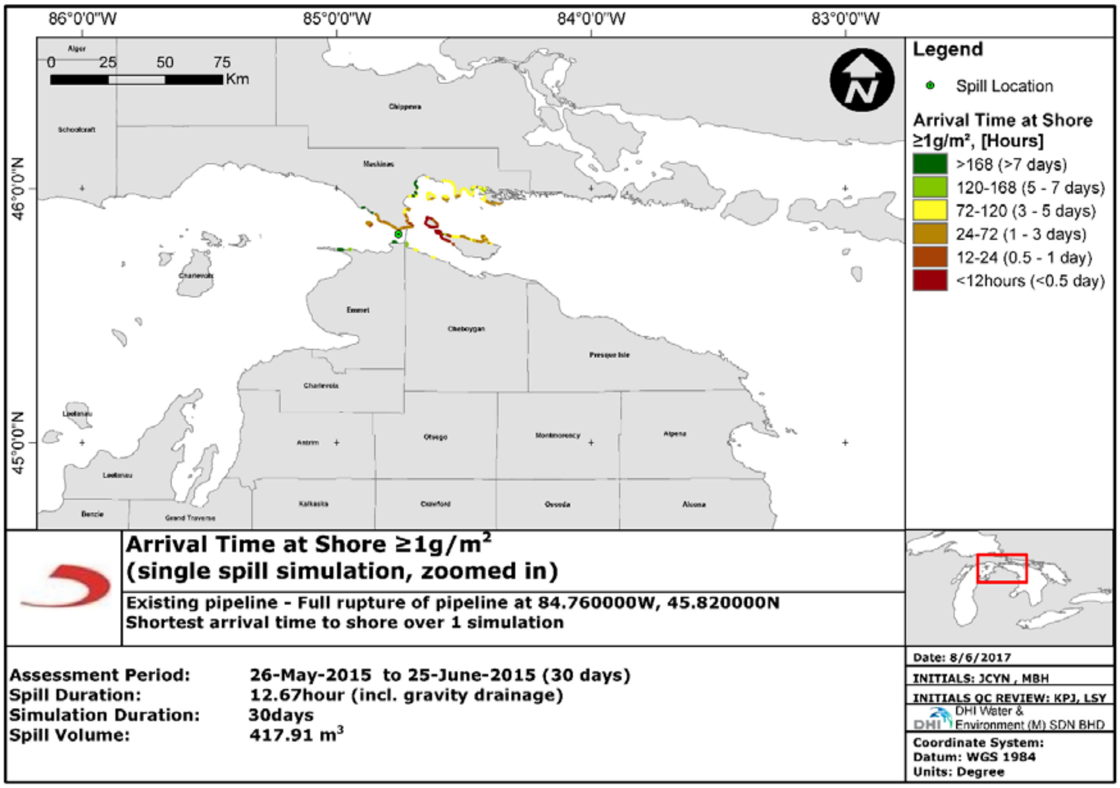


Figure 2-15: Arrival Time to Shore of Spill Trajectory on May 26, 2015

As described previously, the 120 simulations for each scenario have been distributed randomly over the course of the year. For reference, the randomly selected dates and starting times are provided in Attachment 2 (see Appendix S).

2.4.2.2.1.3 Results – Full Rupture Scenario

The oil spill simulation maps show that the majority of the spill trajectories hit the shore of the core zone within the counties Mackinac, Emmet and Cheboygan. Single spill trajectories can travel further depending on the environmental conditions existing at the time of the spill.

All result maps and the summary tables for the simulations are included in Attachment 2 (see Appendix S).

The probability of occurrence of the oil spill in water shows the percentage of time that an oil spill larger than 0.01 g/m^2 occurs. This threshold is chosen to represent an equivalent of approximately 0.01 µm oil slick thickness. According to the *Bonn Agreement Oil Appearance Code*, this oil thickness is described as grey sheen with a rainbow sheen developing with a thickness of approximately 1 µm. A 1-µm slick thickness is close to the practical limit of observing oil in the marine environment (AMSA 2012). However, newer technologies can now observe oil films thinner than 0.1 µm. Environment Canada recorded in the Canadian Atlantic Ocean sheens thinner than 0.1 µm using a state-of-the-art laser oil detection system called a Scanning Laser Environmental Airborne Fluorosensor (SLEAF). From an environmental perspective, 0.01 g/m^2 is a very conservative threshold with little impact on the feathers of birds. A more commonly used moderate threshold is 10 g/m^2, which is associated with mortality of water birds and mammals coming into contact with the oil slick.

The probability is based on analysis of combining all 120 spill trajectory simulations. Figure 2-16 shows the probability that an area is exposed to an oil spill in water based on all simulations, whereas Figure 2-17 shows the 95th percentile. Or in other words, only areas that are hit by at least six spills.

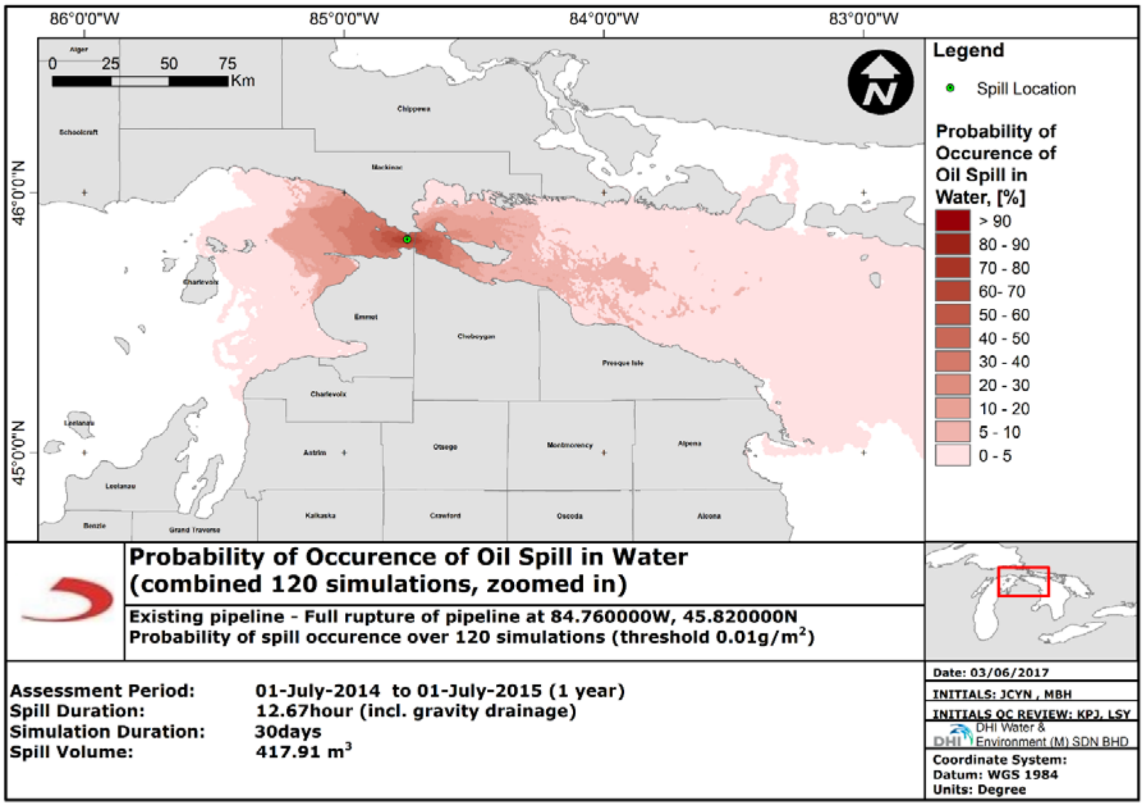


Figure 2-16: 95th Percentile Probability an area is exposed to Spill in Water (Threshold 0.01 g/m^2)

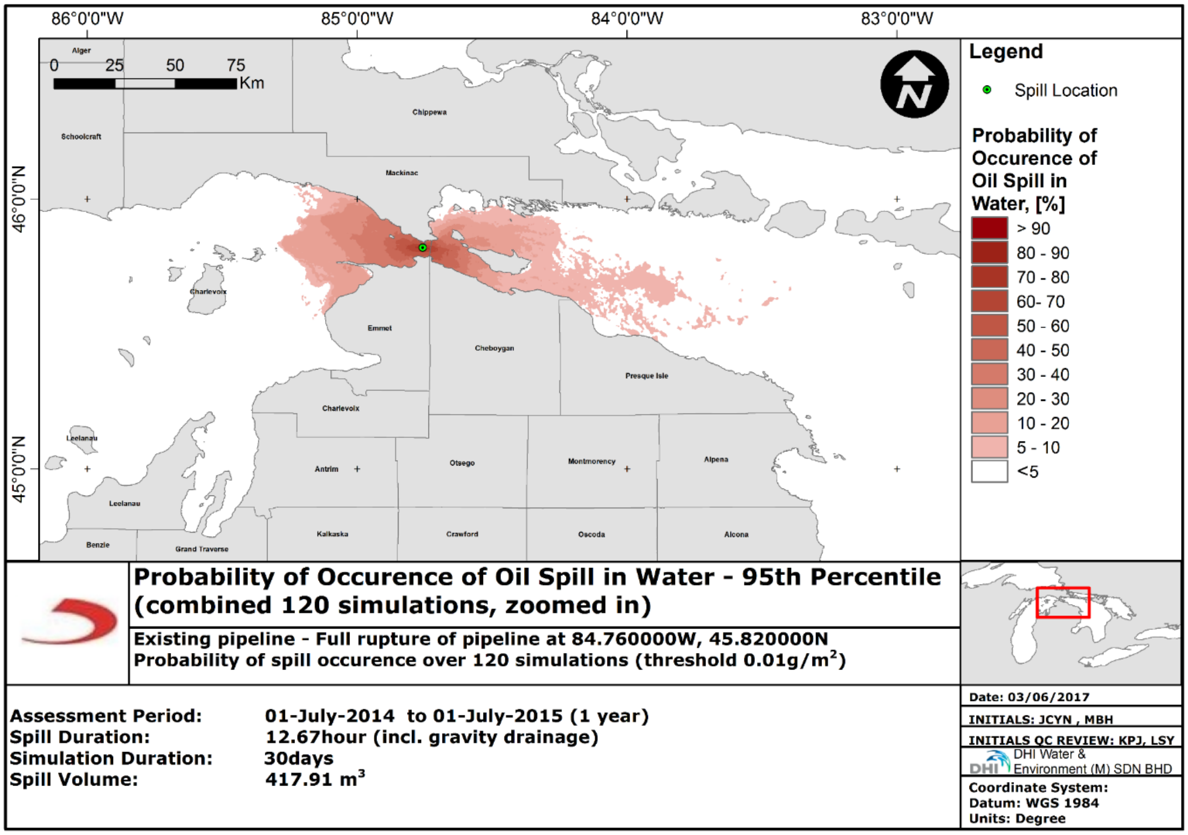


Figure 2-17: 95th Percentile Probability of Occurrence of a Spill in Water (Threshold 0.01 g/m^2)

ZOE maps, as shown in Figure 2-18, represent the shoreline that is being exposed to the combined oil spill scenarios. The maps show the combined result over all 120 simulations with each point depicting the maximum value realized at the shoreline over all 120 simulations. The ZOE classifies the exposure into three categories as described in Table 2-12.

Table 2-12: Thresholds Classification for Shoreline Based on Hydrocarbon Concentration (in g/m^2)

Hydrocarbon Concentration (g/m^2)	Impact Level	Description of Impact
< 1	No exposure	-
1-100	Low	• Barely visible sheen • Likely results in closure of fisheries • Fishing is prohibited • Socioeconomic impact.
100-1,000	Moderate	• Mortally impact water birds and other wildlife associated with water surface • Ecological impact.

Hydrocarbon Concentration (g/m²)	Impact Level	Description of Impact
>1,000	High	• Harmful to all birds that contact with the slick • This is used to define the zone of potential high exposure.

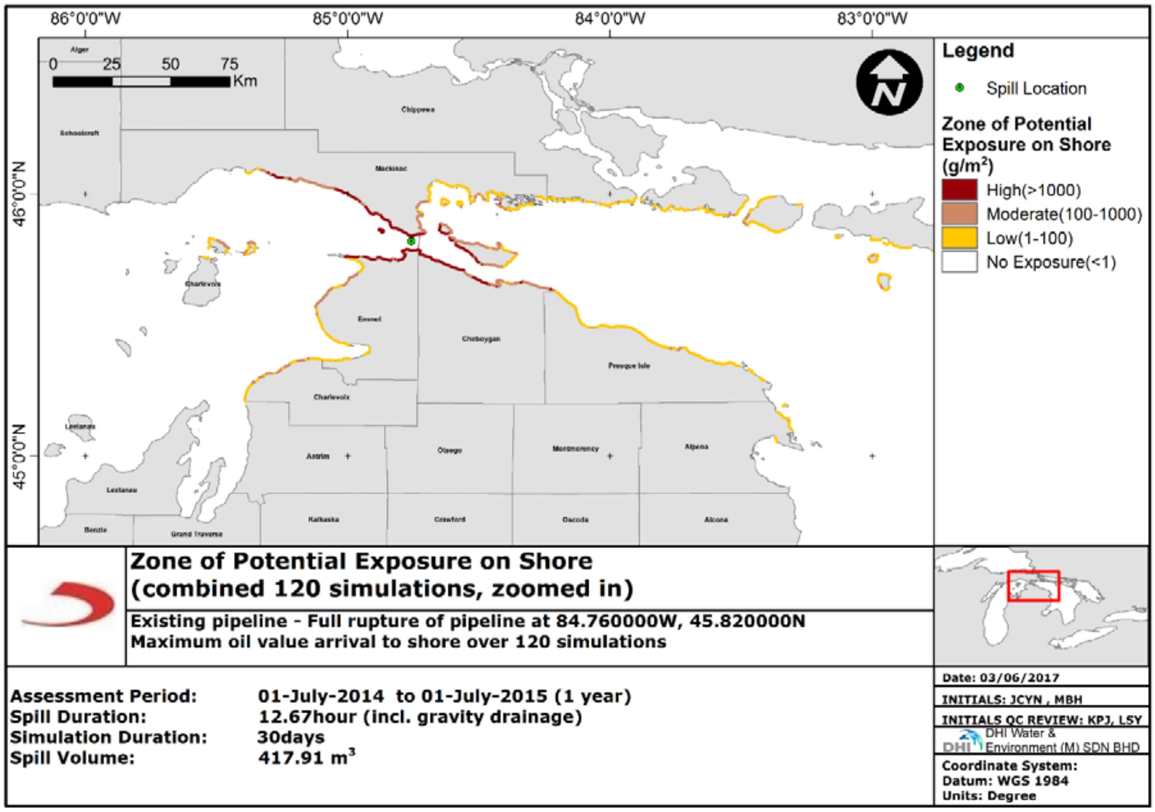


Figure 2-18: Zone of Potential Exposure on Shore (g/m²)

The arrival time to shore predicts the time for the oil spill to reach the shoreline after the time of the spill. All spills are mapped together meaning that the shortest arrival time to shore over all 120 simulations is shown. Longer arrival times to the shore allow for mitigation measures to be put in place to protect key receptors, compared to short arrival times where there may not be time to respond before the oil reaches shore.

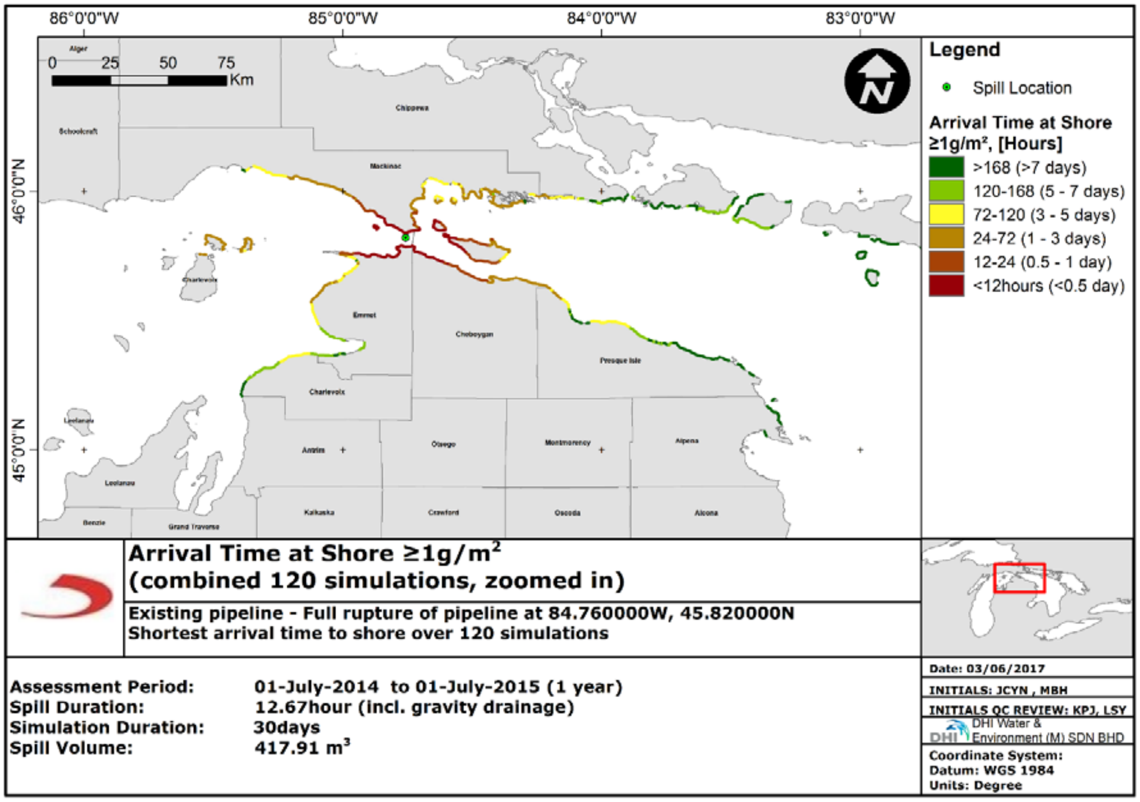


Figure 2-19: Arrival Time to Shore – Full Rupture Existing Pipeline

Besides the assessment of the full year, seasonal-specific patterns are analyzed by dividing the year into four quarters. Each quarter includes 30 simulations, randomly distributed by time of spill. Figure 2-20 presents the probability of occurrence of an oil spill over the four quarters. It is apparent that during the winter season (Q3) the spill extent is the smallest. This is due to the ice cover preventing the spill from fully developing all the way to the shoreline.

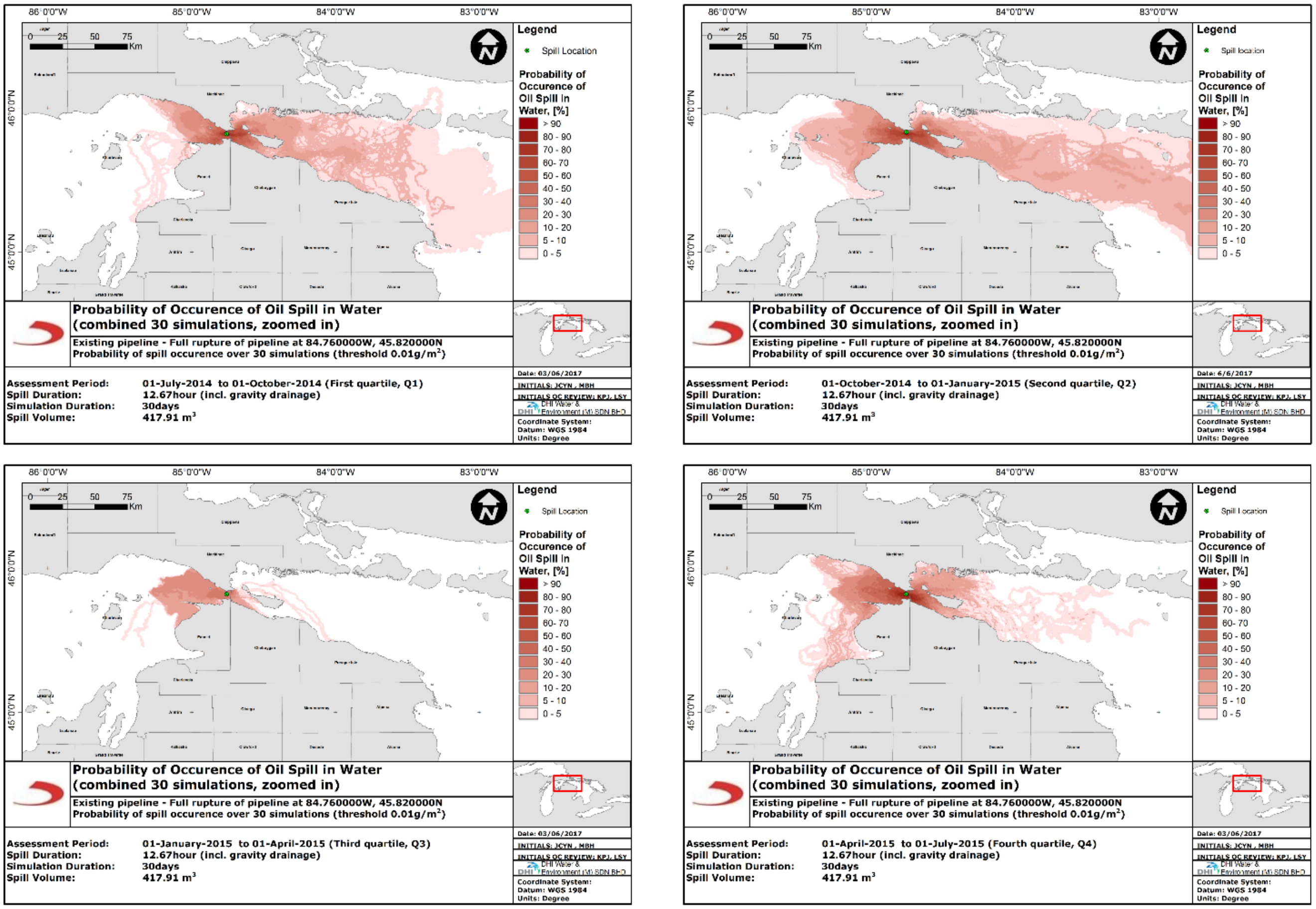
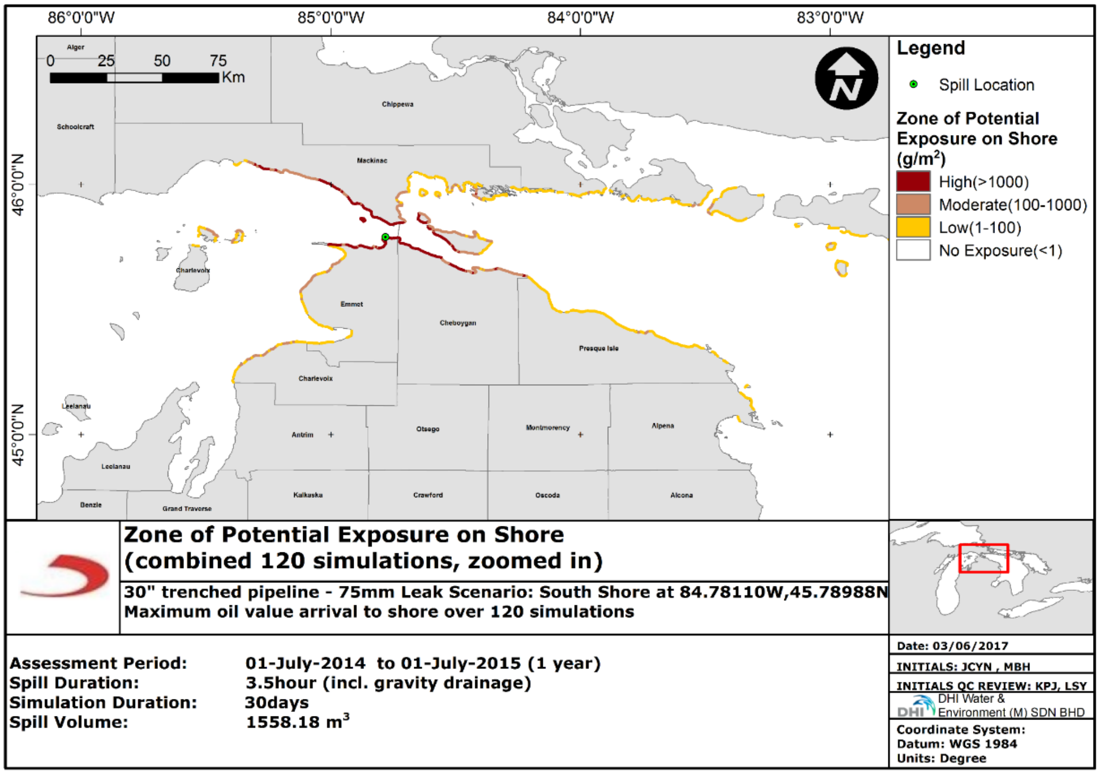


Figure 2-20: Seasonal Distribution of Probability of Oil Spill Occurrence (Top Left: Jul-Sep/Q1, Top Right: Oct-Dec/Q2, Bottom Left: Jan-Mar/Q3, Bottom Right: Apr-Jun/Q4

2.4.2.2.1.4 Results – Leakage Scenarios

The scenarios for pipeline leakages at the northern and the southern shores are similar in terms of distribution of the spill. However, due to larger volumes spilled in the southern shore scenario, the zone of potential exposure receives higher concentrations at the shoreline for the southern shore spill scenario.



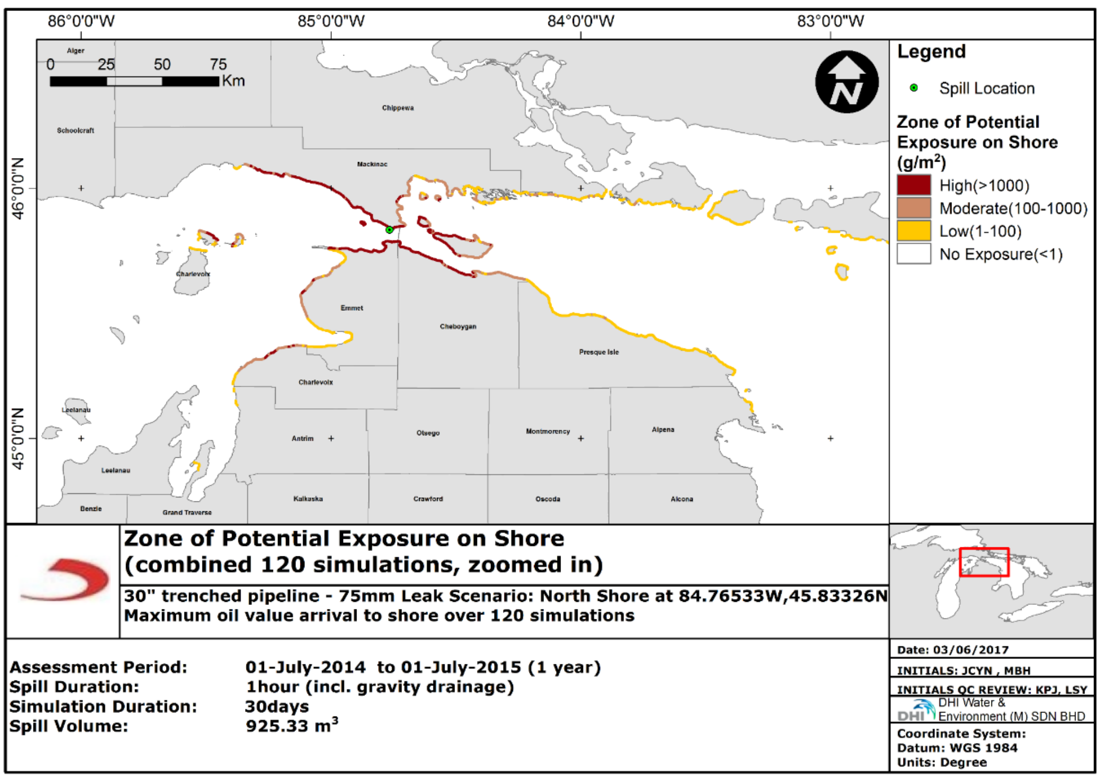


Figure 2-21: Zone of Potential Exposure (Top: Leak on the Northern Shore, Bottom: Leak at the Southern Shore)

2.4.2.2.2 Environmental Oil Spill Analysis

This section applies the spill modeling results from Section 2.4.2.2.1 and discusses potential impacts to sensitive ecological receptors.

2.4.2.2.2.1 Methodology

The methodology for underpinning a discussion on ecological impacts from a Line 5 spill event entailed three different actions, namely:

- Undertaking a review of typical oil spill behavior to demonstrate both short and long term weathering processes and possible receptor exposure
- Applying typical oil spill tolerance limits or known impact threshold levels for representative / indicator species that inhabit or frequent the modeled spill areas
- Using a Rapid Impact Assessment Matrix (RIAM) to rank impact significant of ecological receptor categories potentially impacted by a loss of containment event.

It must be stressed that the above approach is only considered a ‘screening’ of possible ecological consequences. This is because it only identifies at-risk representative sensitive receptors and associated oil spill threshold impact levels. It does not involve, as may be expected in a detailed EIA, comprehensive investigation, and impact analysis of, baseline ecological conditions such as seasonal or daily migration patterns, breeding periods, nursery / juvenile habitat, habitat or ranges of protected species, productivity trends, and / or the ecological dependencies between various organisms. Given the broader context of this study, however, a ‘screening’ level of analysis is considered acceptable.

2.4.2.2.2.1.1 Impact Threshold Levels

The discussion on oil spill weathering supplements oil spill modeling and allows for a fuller understanding of what ecological receptors could be exposed to oil from a spill, leak or rupture. Oil spill tolerance or threshold levels, however, allow the discussion to progress by uncovering proven impacts levels associated with exposed ecological receptors. Here, a comparison is made between oil spill model output parameters such as first oil, slick thickness, etc., known species in the spill dispersion zone and their associated tolerance or threshold levels to characteristics of an oil spill.

Table 2-13 lists threshold limits that are used.

Table 2-13: Threshold Limits

Surface Threshold	In-Water Threshold	Shoreline Threshold
Social - Potential for reduction in intrinsic values / visual aesthetics (low level)	1 g/m^2	11,760 ppb-hrs (entrained) 576 ppb-hrs (dissolved)
Ecological - Potential Toxicity effects / Physical Oiling (moderate level)	10 g/m^2	67,200 ppb-hrs (entrained) 4,800 ppb-hrs (dissolved)
Spill response – Potential for effective spill response on surface waters and shorelines (high level)	> 25 g/m^2	676,800 ppb-hrs (entrained) 38,400 ppb-hrs (dissolved)

Surface exposure relates to the oil slick thickness on top of the water column. At 1g/m^2, which is comparable to approximately 1 µm the oil is visible as rainbow sheen on the water. This may lead to closure of area affected. These low levels of oil slick thickness may result in some impact on the feathers of birds in terms of oiling and possible ingestion while preening (http://publications.gc.ca/collections/collection_2016/one-neb/NE23-186-2010-eng.pdf), however, ecological thresholds are set to 10 g/m^2 or approximately 10 µm in line with observations from French et al [97] that suggest that this level may be mortally to some bird species and other wildlife that come into contact with the water surface.

With lighter oils being more readily soluble in water, toxic aromatic hydrocarbons can enter the water column. French et al [98] and French-McCay [99] [100] showed that sensitivity to toxicity varied for different species (fish and invertebrates) and different environmental conditions between 6 and 400 µg/l (ppb) (dissolved aromatic exposure > 4 days) with an average of 50 µg/l. This included also species during sensitive life stages (eggs and larvae). The low exposure threshold has been chosen as 6 ppb over a 4 day period (96 hours) Tsvetnenko [101]. Acute lethal threshold for environmental receptors has been set to 50 ppb and 400 ppb reflecting acute lethal threshold for 5% and 50% of biota respectively (see French-McCay [99]).

A conservative threshold for the oil deposit at the shoreline is 10g/m^2 as used by French-McCay et al [102] [103]. This threshold relates to enough oil to require shore clean up on beaches or man-made structures (e.g. jetties). A deposit of 10g/m^2 would also trigger the closure of fisheries. This is described as low impact zone.

The threshold for shorebirds and wildlife is set to 100g/m^2 which is based on studies for sub-lethal and lethal impacts (e.g. French-McCay et al. [104] [105] [106]. This threshold is more appropriate for wildlife that enters the water from the shore rather than diving into the surface water. The oil can be described as an oil coat.

In cases where no tolerance levels are available, a brief expert analysis was offered.

2.4.2.2.2.1.2 Rapid Impact Assessment Matrix

Following on from the Tolerance Limit analysis, the well-recognized Rapid Impact Assessment Matrix (RIAM) methodology for assessing and summarising the overall significance of impacts was applied to provide an indication of the most vulnerable ecological receptors. This methodology allows for rapid transparent presentation and summary of the overall impacts of a Project or Alternative; and ultimately aids in pinpointing which impacts or Alternatives are most significant.

With RIAM, the significance of an impact is determined by translating an environmental score (ES) to impact significance (‘Slight,’ ‘Minor,’ ‘Moderate,’ etc.), via a predetermined list of impact levels that correspond to a range of ESs. The main thrust of the RIAM tool is therefore, to assign an environment score to each relevant environmental component of a project.

- The formula for determining the ES is as follows:
- Environmental Score (ES) = I*M*(P+R+C).

The formula variables are defined as:

- (I) Importance – Assigns a level of importance in terms of variables such as spatial extent and socio-political interests related to the impact

- (M) Potential Impact Magnitude– Expresses the level of impact (i.e. deviation from baseline in relation to an established evaluation framework) in a physio-chemical parameter, risk abatement benchmark, or the scale of loss/change to ecological and socio-economic receptors
- (P) Permanence – Assign a score based on the duration of an impact
- (R) Reversibility – The score expresses whether an impact is permanent or reversible
- (C) Cumulativity – A score is defined based on the cumulative potential of an impact.

The RIAM approach generally starts with an analysis of magnitude of impact of the state (M) of a pollutant or environmental aspect (i.e. receptors) in relation to an established acceptability standard or benchmark; followed by assignment of a corresponding RIAM value. This is followed by an assessment of the Importance (I), Permanence (P), Reversibility (R) and Cumulativity (C) of the particular environmental receptor, assigning a RIAM value and simply completing the ES formula. As previously mentioned the ES is then translated into positive or negative levels of 'slight, minor, moderate or major' impact significance.

Explanation of framework for applying RIAM values and translating ESs into significance categories is provided in Attachment 4 (see Appendix S).

2.4.2.2.2.2 Spill Behavior

To frame the discussion on possible consequences to representative receptors, the following subsection provides an overview of key physiochemical characteristics of an oil spill. When released into the water environment, oils can undergo a series of physical and chemical changes, i.e. spreading, drifting and weathering depending on the type of oil spilled (i.e., their specific gravity, viscosity, volatility, solubility and surface tension), the spill size, the environmental conditions (i.e., hydrodynamics, water quality and climate conditions) and the onset times of the spill.

Table 2-14 describes weathering processes and categorizes into 'water surface' and in the 'water column' categories.

Table 2-14: Weathering Processes

On the water surface			
Processes	Onset Time	Factors of Influence	Behavior
Spreading	Immediately on spill	Viscosity and surface tension of oil Wind speed Wave and current speeds	Increases the overall surface area of the spill Enhances mass transfer via evaporation, dissolution and later biodegradation.
Evaporation	Within hours or days	Volatility of oil Thickness of slick	Vaporization of lighter or more volatile hydrocarbons where residual oil becomes denser and more viscous It accounts for 75% mass lost from condensates and ultra-light oils, 20-30% from light oils and ≤10% from heavy oils [107]
Photo-Oxidation	Over months or years	Presence of sunlight	Oil reacts with oxygen in the presence of sunlight to form products that are either more water soluble or persistent compounds called tar balls It accounts for <0.1% of mass loss per day [108]
Emulsification	Over months or years	Wind/Wave actions	Formation of mixtures of oil and water droplets either water-in-oil or oil-in-water emulsions which increases the volume and surface area of the spill. Emulsification is less likely to occur in freshwater, even for spills of heavier oils, due to insufficient physical mixing.
In the water column			
Dissolution	Within hours or days	Solubility of oil	Dissolution is the dissolving of oils in the water column. Only 2-5% of oil is loss by dissolution [109] as many soluble components are also volatile which evaporates at a rate of 10 to 1000 times faster than dissolution [110]
Natural Dispersion	Within hours or days	Viscosity of oil Wave and current speeds	Dispersion occurs as oil droplets detach from the slick and become entrained in the water column. Depending on the droplet size, depth and mixing, larger droplets may coalesce and resurface while smaller droplets may remain dispersed in the water column [109] Lighter oils tend to produce smaller oil droplets due to their lower viscosity.
Submergence and Sedimentation	Over months or years	API Gravity of oil	Sedimentation is the submergence or sinking of oil which become entrained in the underlying sediments. This usually occurs for heavier oils with higher density than the water column due to adhesion to sediment particles.
Biodegradation	Over months or years	Biodegradability of oil Nutrient levels	It is the breakdown of oil by naturally occurring microorganisms. Oil degradation is generally faster in well-aerated water column under aerobic conditions.

The oil spill modeling results in Section 2.4.2.2.1 cover and/or illustrate the explained shorter-term (i.e. 'immediately' and within hours, days or up to a month) weathering processes. The overall processes are, for the most part, similar for freshwater and marine water, as they generally pertain to oil properties in terms of chemistry and composition.

2.4.2.2.2.3 Overview of Potential Consequences

The potential light oil spill release from Line 5 pipeline failure in the Mackinac Straits was numerically modeled in order to gain a probabilistic understanding of the spreading which is in all instances would entail dispersion into large areas of Lake Michigan or Lake Huron open water or shorelines. Longer-term weathering processes such as 'emulsification' and 'submergence / sedimentation' also illustrate that oils would persist in the water column or benthic sediments / substrates. It is also noteworthy that ice cover in winter could prohibit the spill from reaching the shore or a storm event may result in much further spreading. Oils trapped in sediments can also be re-suspended in the water column due to later disturbance of the sediments.

Also, while there are certain generalities in spill behavior, Table 2-15 also points out how oil properties (e.g. density, viscosity, vapor pressure, solubility) affect spill behavior. As previously mentioned, the largest proportion of product currently transported in Line 5 is a light crude oil (5/6 of the time). This oil is liquid at room temperature, has a density lower than water (i.e. it would float on water), a high vapor pressure (i.e. it evaporates more readily than heavier oil) and higher solubility in water compared to heavier oil. The following approximate properties are assumed for the environmental study [111].

Table 2-15: Effect of Oil Properties on Spill Behavior

Oil Properties	Value
Density:	820 kg/m^3
Flash Point:	< -30 C
Aromatics (BTX):	Benzene (0.26 vol%), Toluene (0.90 vol%), Ethyl Benzene (0.19 vol%) Xylenes (1.16 vol%)

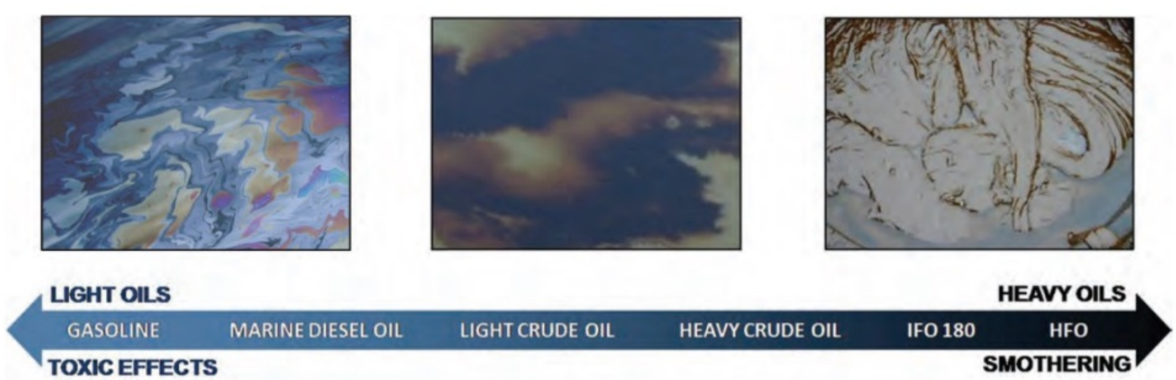


Figure 2-22: Typical effects on organisms ranging across toxicity spectrum from light oils/oil products to smothering intermediate and heavy fuel oils and weathered residues (extracted from ITOPF [112])

As apparent in Figure 2-22, above, lighter fuels tend to impact affect environmental receptors such as fish, benthic invertebrates, and aquatic vegetation in different ways. Lighter are generally more toxic due to components that are water soluble.

Thus, while the oil spill modeling clearly quantifies the dispersion of a light oil spill from Line 5, the combined above-mentioned factors suggest several ecological receptor oil exposure consequences related to a Line 5 spill, namely:

- portions of the light oil will dissolve resulting in decreasing toxin concentrations towards the outer potions of the modeled spill plume or slick
- in relation to the above, a higher probability of a potentially toxic direct lethal effect to susceptible species, e.g. sessile or species unable to move away from certain habitat
- as the plume or slick disperses further and comes into contact with the shore (e.g. with likely heavier hydrocarbon chains due evaporation of lighter fractions), direct contact with vegetation and shoreline / wetland habitats
- In relation to the above, lake waters, shorelines and wetlands would experience:
    - oil smothering impacts (e.g. coating fur or feathers) to sessile species or juveniles unable to escape the spreading oil leading to stresses at potentially lethal or sublethal levels
    - oil trapped in shoreline vegetation or coating vegetation (incl. floating vegetation) which could in turn be remobilized under certain metrological and hydraulic conditions
    - oil smoothing of certain critical habitat (e.g. foraging or spawning grounds) making them inaccessible to various species, thereby causing stresses at potentially lethal or sublethal levels
- mobile oils in lake water that undergo longer- term emulsification’, ‘submergence / sedimentation’ and photo-oxidation, and consequentially longer term ecological exposure to lighter oil droplets in the water column, contaminated benthic sediments and tar balls.

The sections that follow provide a brief analysis of the potential ecological impacts to representative categories of species in the Mackinac Strait, which is then followed by a RIAM Matrix illustrating the relative significance of impact to each.

It is also noted that that the area of exposure is very similar for the full rupture and leakage scenarios even though the level of exposure varies. However, as the variation in exposure is all well above ecological threshold values, the actual impact does not change.

2.4.2.2.2.3.1 Birds

More than 140 species of birds depend on Michigan’s coastal habitat during their life cycle. Coastal wetlands, beaches, sand dunes and remote islands provide food and shelter for both resident and migratory species. Oil spill impacts birds, particularly water birds, in two ways, i.e.:

- Direct contact with oil and oiling of the plumage
- Ingestion of oil [113].

When bird plumage gets into contact with oil, the natural waterproofing of the feathers is lost. This could result in the loss of buoyancy causing the bird to drown. Further, exposed skin due to impaired feathers affects heat regulation resulting in hypothermia (cooling) or hyperthermia (overheating).

As the bird rids its plumage of the oil through intensive preening of the feathers, it could ingest the oil leading to direct toxicity or internal bleeding, depending on oil toxicity.

Depending on bird forage behavior, birds can be exposed to an oil spill on the open water or along the shore. Birds that typically dive for food are at risk of getting oiled when diving through the oil slick layer on the water surface. Bird exposure threshold to oil is known to be 10 g/m^2.

Birds that forage in the shallow waters along the shoreline (waders) typically experience less contact with oil as they do not fully submerge but wade through the water (feet and some plumage). The threshold for shoreline birds is hence 100 g/m^2.

Figure 2-23 below shows the prime bird habitat within the Mackinac region as identified from NOAA's environmental sensitivity index (ESI) [114].

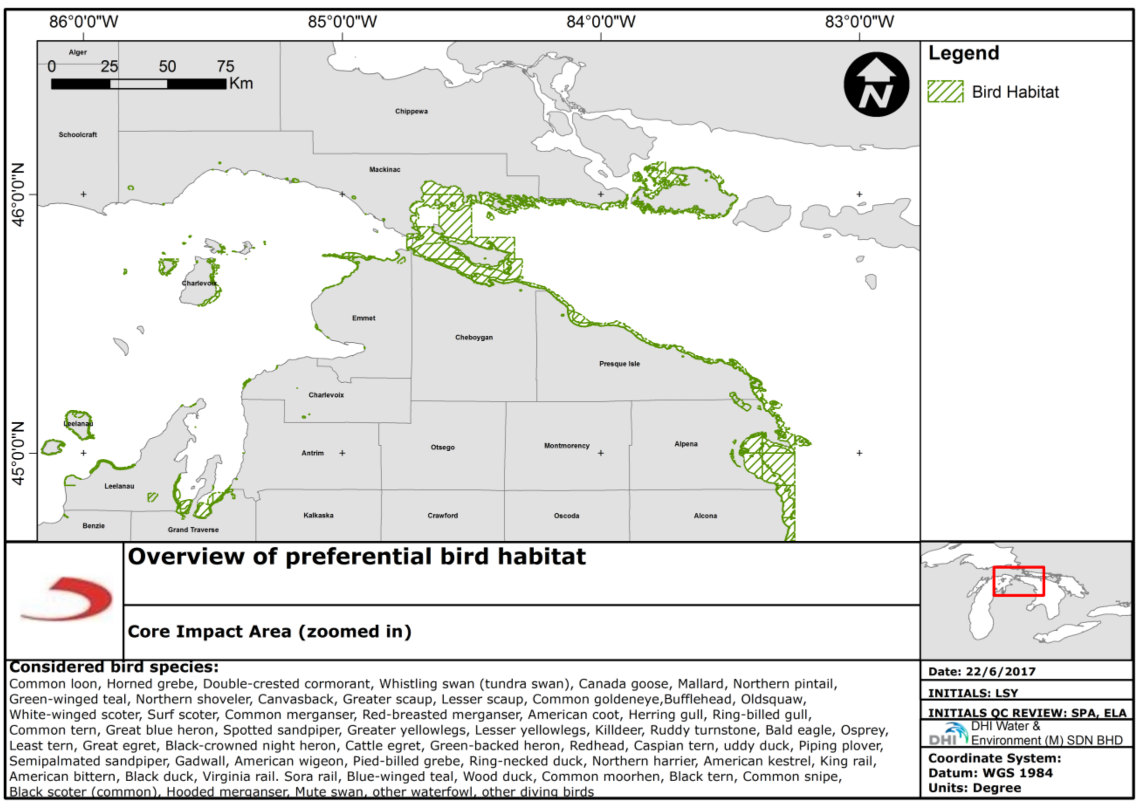


Figure 2-23: Bird Habitats within the Mackinac Region

2.4.2.2.2.3.2 Fish

There is a large number of fish species present in Lake Huron and Lake Michigan. For example, 115 species of fish are found in Lake Huron while Lake Michigan is a habitat for at least 134 species of fish from various Trout, Minnow, Bass, Carp and Salmon families. Many of the fish in Lake Huron and Lake Michigan are migratory species that migrate up the rivers.

During an event of an oil spill, these fish can be impacted through direct or indirect exposures to oil, where impacts would occur due to exposure to concentrations of soluble oil toxins that are lethal to fish, and/or indirect pathways of sub-lethal exposure to toxins that could impact the health and fitness of the fish [115]. Nevertheless, fish have shown avoidance behavior to oil polluted areas in marine waters but such behavior is not apparent in shorelines where oiling, emulsifying and large oil deposits may occur, limiting available space for escape. Juvenile fish are, however, more susceptible to the toxic effects than adult fish. One of the major impacts on fish population will be the reduction in suitable habitat and carrying capacity of an area due to reduced food supply and significant reduction in the availability of nursery and spawning areas that are often located in the shallows (Figure 2-24).

These fish are food source for many birds and mammals living along the great lakes, and they provide other socio-economic benefits such as recreational fishing opportunities. These impacts could then result in the disruption of the functional inter-relationships of aquatic/palustrine communities and ecosystems.

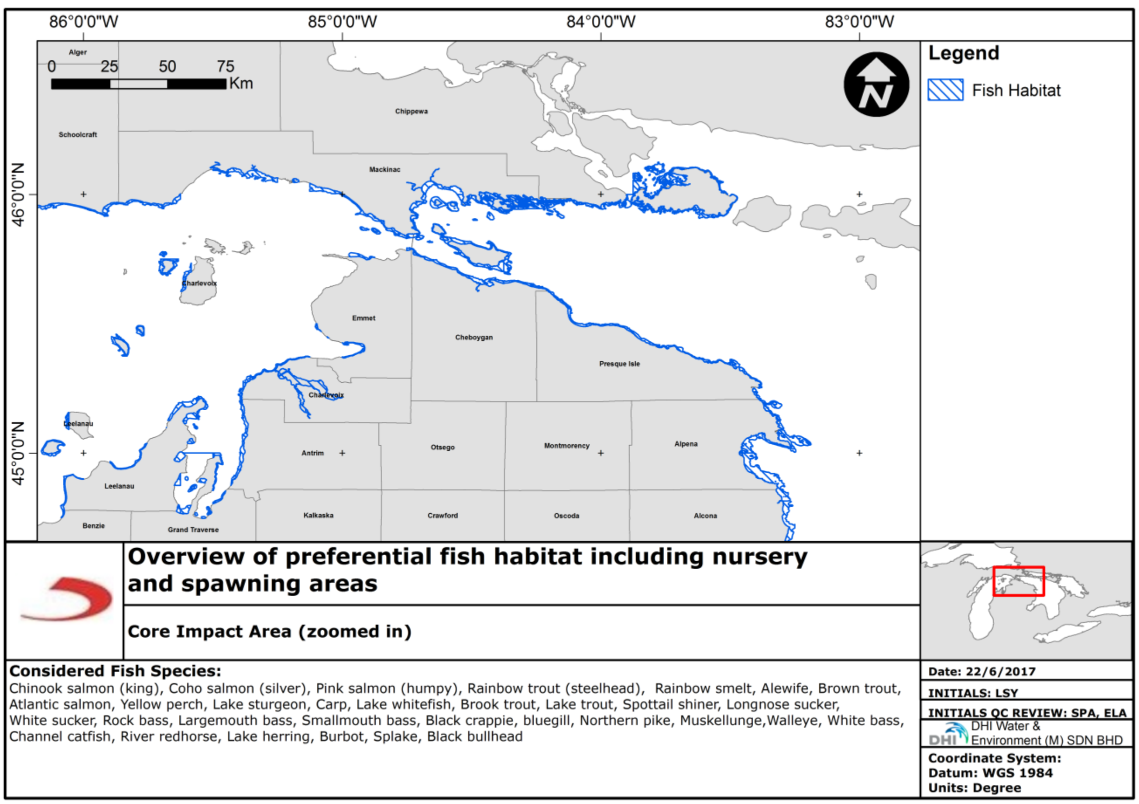


Figure 2-24: Fish Habitats (Incl. Nursery and Spawning Areas)

2.4.2.2.2.3.3 Herpetofauna

Some of the reptiles that can be found in the Great Lakes, include a number of turtles such as snapping turtles, spotted turtles, painted turtles, spiny softshell turtles, Eastern

Box turtle, and snakes such as Eastern Mississauga Rattlesnake, Northern Copperbelly Water Snake. When exposed to oil spills, both turtles and snakes undergo physiological changes that could affect their survival and reproduction. For example, studies have shown that turtles exposed to oil spills have a higher chance for deformities and embryo death during reproduction [116], while snakes are well known to accumulate PAH in their skin.

A large number of amphibians (in particular frogs, toads and salamander) live in the Great Lakes. These animals are particularly sensitive to oil spills as their thin permeable skin makes it easy for pollutants to enter their bodies [117]. The chronic exposure to toxic components in light oils after oil spill could therefore result in an overall additional stressor on animals that are surviving in a carefully balanced system.

2.4.2.2.2.3.4 Mammals

A number of mammals that live along the lake shore, including river otter, beaver, muskrat, mink and northern raccoon, are known to be particularly sensitive to oil spills. Populations of these animals are mainly found on Bois Blanc Island (extensive and old beaver works) and around De Tour, both well inside the project area and those potentially hit by an oil spill. As with birds, the oiling of mammals prohibits proper insulation and water repellant of the fur, resulting in hypothermia and/or potentially drowning. In other cases, these animals could also ingest oil via grooming. There is also a risk of cumulative impact through bioaccumulation of toxins when these mammals consume fish that are exposed to oil. This is especially true for many mammals such as river otter being a top predator, thus making this species particular sensitive to oil spills in the long-term. It has been found that the threshold for an impact on shoreline living mammals is 100 g/m^2.

Figure 2-25 shows the mammal habitat within the Mackinaw region.

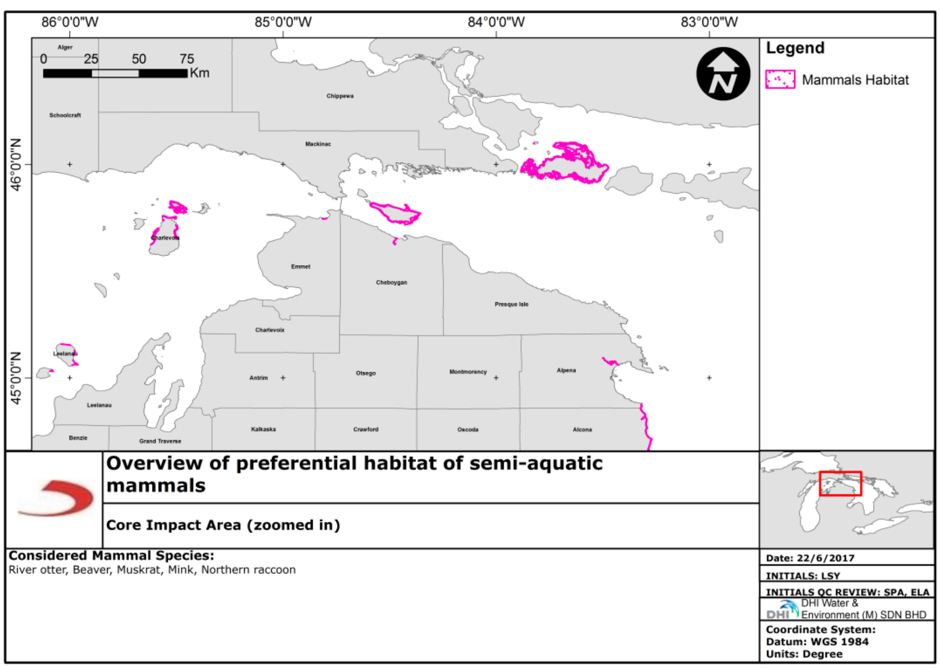


Figure 2-25: Mammal Habitat

2.4.2.2.2.3.5 Aquatic Fauna

An important part of the complex food web of Lake Michigan and Lake Huron food web is the presence of keystone species that support the fish and bird populations. These keystone species are generally small animals known as diporeia, also known as scuds, sideswimmers, beach hoppers, and sand fleas. They belong to the group of invertebrates called amphipods and are about 1.25 centimeters long. Diporeia have been declining over the last years due to invasive species (in particular zebra mussels). Potential oil spill can, therefore, put additional pressure on the population due to exposure of toxic components soluble in water [118]. Diporeia has, to some extent, the ability to tolerate PAH-related contaminants by diffusion [119] but bioaccumulation can still lead to toxic effects further up the food chain. As keystone species, the collapse of diporeia population would put the complex food web at risk as it will initiate a ‘domino effect’ along the food chains.

2.4.2.2.2.4 RIAM

As previously mentioned, RIAM was included in the methodology approach to provide an indication of the most vulnerable ecological receptors to a Line 5 oil spill. These results of this analysis are illustrated in Table 2-16, below, which have been derived based on the above discussions and the RIAM ranking values (see Attachment 4 in Appendix S).

Table 2-16: Tabulated Line 5 Oil Spill RIAM Results

Impact on	Magnitude of Potential Impact	ES	I	M	P	R	C
Impacts on Avian communities	Major Negative Impact	-128	4	-4	3	2	3
• Diving birds	Major Negative Impact	-128	4	-4	3	2	3
• Wading birds	Significant Negative Impact	-64	4	-2	3	2	3
Impacts on Fish health and fitness	Significant Negative Impact	-64	4	-2	3	2	3
Impacts of Fish reproduction	Major Negative Impact	-128	4	-4	3	3	3
Impacts on Herpetofauna (physiological impact)	Significant Negative Impact	-64	4	-2	3	2	3
Impacts on Mammals	Significant Negative Impact	-64	4	-2	3	2	3
Impacts on Other general Aquatic Fauna	Significant Negative Impact	-72	4	-3	3	3	3
Impacts on Keystone aquatic fauna	Major Negative Impact	-144	4	-4	3	3	3

As apparent, in the spill-specific ZOE, a Line 5 oil spill is assessed to lead to either ‘significantly’ or ‘major’ negative impacts to all ecological receptor categories in the Mackinac Strait. Of the included categories, however, species more likely to come into direct contact with the spill plume are ranked at ‘major’ levels of impacts. This is apparent with, for example, diving birds, fish eggs or juveniles. The category ‘keystone aquatic species’ also received an ‘major’ ranking, due to cumulative stress put on them by oil toxin concentrations and their role in overall ecosystem health.

2.4.2.3 NGL Release Analysis

A simulation of the NGL releases caused by failure of the Straits pipelines was conducted using PipeTech software. PipeTech is a computational fluid dynamics (CFD) computer program that predicts transient fluid flow dynamics following the failure of pressurized pipelines. The program provides NGL discharge rates, which are subsequently used to predict the dispersion and travel behavior of gas plumes in and on the surface of the water (see Section 2.4.2.4).

2.4.2.3.1 Methodology

Consistent with the oil release analysis performed for environmental consequence analysis (see Section 2.4.2.1.1), NGL release sizes were determined based on the Principal Threats identified in Section 2.4.1. In that respect, an assumption of an FBR was associated with the threat of anchor interaction and spanning, and a 3-in. (75 mm) hole was associated with Incorrect Operations.

To account for the variation in the water depth and investigate the impact of the release depth on the release rates, five scenarios were modeled:

1. A release from a full-bore opening in the shipping channel at a depth of 246 ft. (75 m), representing a release at the deepest location along the Straits pipeline.
2. A release from a full-bore opening in the shipping channel at a depth of 115 ft. (35 m), representing a release at a medium depth location along the Straits pipeline.
3. A release from a 3-in. (75 mm) diameter hole at depth of 227 ft. (69 m), representing a release at the deep end of the shipping channel.
4. A release from a 3-in. (75 mm) diameter hole at depth of 115 ft. (35 m), representing a release at a medium depth location along the crossing.
5. A release from a 3-in. (75 mm) diameter hole at depth of 33 ft. (10 m), representing a release at a location with shallow water depth along the crossing.

Because the main driving force in NGL releases is the pressure differential between the pipeline pressure and the ambient pressure, the minor differences between the East and West pipelines' elevation profiles do not result in a significant variation in the discharge rates. For modeling purposes, a simplified pipeline profile was used based on the West segment profile (see Attachment 1 in Appendix S).

Figure 2-26 shows the West segment elevation profile and representative released locations.

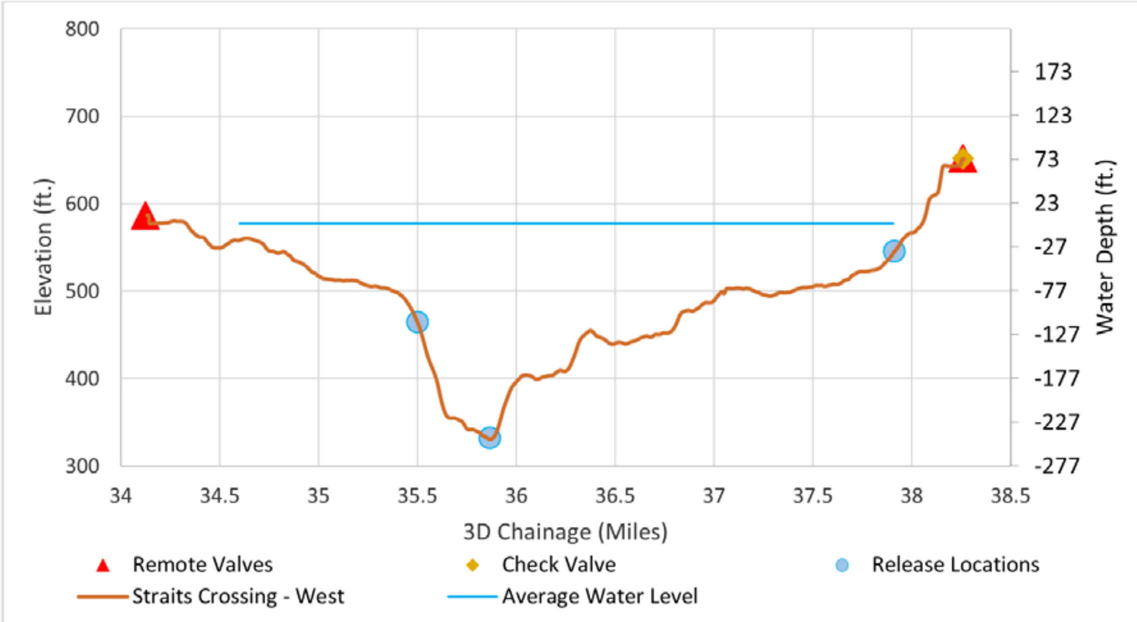


Figure 2-26: Straits Pipeline Crossing Profile

Attachment 1 in Appendix S contains detailed information about modeling inputs, assumptions and approach.

2.4.2.3.2 Results

Table 2-17 presents the average release rates over the initial 120 s of the release. Average release rates are employed for reporting purposes because of rapid reduction in the initial release rate. This typically occurs in full-bore events because of rapid reduction in pipeline pressure.

Table 2-17: NGL Release Rates

Scenario No.	Release	Principal Threat	Water Depth ft. (m)	Average Release Rate over Initial 120 s of Release lb/s (kg/s)
1	Full-bore failure at deep location	Mechanical damage Weather and Outside Forces	246 (75)	1,057 (479)
2	Full-bore failure at medium depth		115 (35)	1,964 (891)
3	3-in. (75 mm) leak at deep location	Incorrect Operations	227 (69)	242 (110)
4	3-in. (75 mm) leak at medium depth		115 (35)	237 (108)
5	3-in. (75 mm) leak at shallow depth		33 (10)	158 (72)

As presented in Table 2-17, an FBR release at a depth of 115 ft. (35 m) results in a higher discharge rate than a release at a depth of 246 ft. (75 m). This is due to the greater hydrostatic pressure at greater depth.

In the case of the leak scenarios, the releases are modeled using a 30-in. pipeline diameter. The leak involves a relatively small hole diameter of 3 in (75 mm), resulting in an instantaneous drop to choked flow upon breach. This leads to a very slow decompression and almost constant discharge velocity and discharge mass rate. In essence, given the very large amount of upstream inventory, the pipeline behaves much the same as an infinite reservoir, and the variation between release rates from a 30-in. and a 20-in. diameter pipe will be negligible. This principle is also confirmed by the insignificant variation between the release rates at different depths.

It should be noted that the mass release rate for Scenario 5 is smaller compared to those in the other leak scenarios. This is due to the larger distance between the upstream feed and the leak location resulting in lower local pressure in the pipe (Figure 2-26).

Attachment 1 in Appendix S contains detailed simulation results, including the change in discharge rate over time.

2.4.2.4 NGL Dispersion Analysis

Following a pipeline failure at the straits crossing, discharged NGLs could travel to the surface of the water and form a flammable cloud (i.e. a mixture of air and a combustible concentration of flammable material). Such a flammable cloud, if ignited, would result in a flash fire which is considered a safety hazard to the population within the area.

NGL dispersion modeling was conducted to predict the travel behavior of the plume and to evaluate the extent of the area covered by the lower flammability limit (LFL) cloud.

2.4.2.4.1 Methodology

The NGLs which are carried by Line 5 mainly include lighter hydrocarbons (i.e., C3 and C4). A breach in the line would initially result in a two-phase release as detailed in Attachment 1 (see Appendix S). However, the majority of the liquid phase will evaporate as the fluid expands and travels through the water column. Thus, NGL releases have been treated similar to a gas release for the purpose of this analysis. To better predict the behavior of NGLs once released, the assessment methodology involves review of each of the following elements:

- Under Water Release Behavior

  Prediction of plume behavior in the water as it travels to the water surface.

- Boil Zone Development

  Establishing a gas boil zone diameter on the water surface.

- Dispersion Modeling

  Development and dispersion of the flammable plume in the atmosphere.

- Lake Surface Fire Modeling

  Assessment of thermal radiation resulting from ignition of the flammable cloud on the lake surface.

- Atmospheric Conditions

  Review of the weather and wind conditions within the Straits region and evaluation of the impact of wind variations on the flammable plume behavior.

- The approach and assumptions associated with each of these elements are further discussed below.

2.4.2.4.1.1 Under Water Release Behavior

Releases of gas below water level will result in a plume rising to the water surface. There are a number of processes, as listed below, which will ultimately affect how the plume will behave [120].

- Under high pressures and low temperatures, and in the presence of water, gas can convert to a solid hydrate.
- The free gas can dissolve into the surrounding water body.
- The gas will rise, be subjected to lower pressures, and expand due to the lower pressures.
- The gas release could result in a plume rising to the surface at velocities which can override the effects of the prevailing water currents.

Gas hydrates are solids formed under pressure when low molecular weight gases are contacted with water. As discussed in [120], no hydrates would be expected to form for releases in water depths shallower than 960 ft. Therefore, no account for hydrate formation is included for shallow water releases such as releases in the Straits.

Additionally, as the release occurs in a large body of water, there is an opportunity for the gas to dissolve in water which would reduce the bubble size and, if the residence time in the water column is long enough, it may result in complete consumption of the gas bubble. However, for water depths of less than 960 ft. the time for the plume to reach the water surface is expected to be such that little of the gas would be lost due to dissolution [120]. In this assessment, all of the released gas is assumed to rise to the surface. Furthermore, in the analysis, due to the relatively shallow depth of the release location, it is assumed that the gas plume travels vertically to reach the water surface, and no account for the water currents and their effect on the plume is taken.

2.4.2.4.1.2 Boil Zone Development

For NGL releases from the Straits crossing pipelines, the diameter of the boil zone on the water surface, is assumed to be 20% of the cone height (i.e. water depth) [121]. It is reasonably conservative to treat the plume rising through the water as forming a cone with an angle of about 12 degrees, so that the diameter of the boil zone on the water surface is about 20% of the cone height [121]. Furthermore, based on a study of subsea blowouts [122], this diameter may be used regardless of the outflow rate.

The analysis, also, assumes that the concentration of gas is uniform throughout the boil zone. Although the distribution of concentration may be higher in the center, with a Gaussian distribution across the boil zone, applying a constant concentration across the pool does not significantly affect the hazard range as mixing across the pool area occurs within a short distance after gas exits from the water surface. [121]

It is noted that the above assumptions discount the effects of gas bubble dissolution and deep water currents on the shape and concentration of the gas plume. As mentioned previously, these elements are not expected to have significant impact on plumes from releases in shallow waters such as the Straits.

2.4.2.4.1.3 Dispersion Modeling

The dispersion of flammable gas was modeled using the Unified Dispersion Model (UDM) within DNV PHAST v. 7.11. This type of analysis effectively ignores the effect of blockage and turbulence caused by any equipment which could be in the area to give a conservative estimate of the maximum range of hazardous concentrations of gas. As the modeled release is on water surface, there would be no (or minimal) blockage in the area so it can be concluded that this type of analysis is suitable for modeling this release scenario.

The discharge rates provided in Section 2.4.2.3 were used as inputs to the dispersion modeling. As discussed in Attachment 1 (see Appendix S), the isolation time for a full-bore event is assumed to be 13 minutes, and once the pipeline is isolated there is a noticeable drop in the mass discharge rate. Bearing that in mind, a 20-minute release duration is used for the purpose of modeling NGL releases from a rupture event.

A 30-minute period was used for dispersion modeling associated with leak scenarios as the isolation time is longer in such cases (i.e., 33 minutes). The flammable clouds resulting from a leak scenario reach steady state in less than 30 minutes. A longer release duration will not impact the size of the cloud.

2.4.2.4.1.4 Lake Surface Fire Modeling

A surface fire is only considered for cases in which the gas plume can reach the surface with sufficient velocity and concentration to create a flammable gas cloud. If the gas emerges at a concentration below the flammable limits or if the burning velocity is greater than the velocity of the gas as it is released at the water surface, a sustainable surface fire or flammable plume will not be possible. Analysis in Section 2.4.2.3 demonstrates that failure of the Straits pipelines results in the sufficient discharged rates to create a flammable mixture on the lake's surface.

DNV PHAST v. 7.11 was used to determine the thermal radiation levels resulting from potential fires on the water surface. The standalone *pool fire* model was used to model the water surface fires. The pool fire diameter was based on the boil zone diameter as described previously.

2.4.2.4.1.5 Atmospheric Conditions

Atmospheric stability (stable, neutral, or unstable) affects the rate of dilution of the plume and the width of the plume. The Pasquill classification, which is commonly used for dispersion modeling, identifies six classes ranging from A (very unstable) to F (very stable).

As recommended by [123, p. 4.17], for this analysis, six representative weather categories were selected for modeling purposes, covering the stability conditions of *stable*, *neutral*, and *unstable*, and the wind speed conditions of *low*, *medium*, and *high*.

Table 2-18: Wind and Stability Category [124]

Wind Speed Category	Wind Speed Range	Representative Wind Speed[16]	Probability of Occurrence	Pasquill Stability Class
Low	≤ 4.5 mph	4.5 mph	12%	F – Moderately stable
				D – Neutral
Medium	4.5 mph – 13.4 mph	8.9 mph	63%	B – Moderately unstable
				D – Neutral
				E – Slightly stable
High	≥ 13.4 mph	16.6 mph	25%	D – Neutral

Table 2-19 lists other atmospheric parameters used take into account the prevailing conditions within the region for the purpose of modeling.

Table 2-19: Atmospheric Parameters

Parameter	Value [90]	Unit
Average Atmospheric Temperature	62.4	ºF
Relative Humidity	80	%
Solar Radiation Flux (Day)	0.3	kW/m^2
Atmospheric Pressure (absolute)	1.01	bar

2.4.2.4.2 Results

Table 2-20 includes the LFL distances resulting from releases at several representative depths.

Table 2-20: Flammable Cloud Distance

Release Size	Release Depth ft. (m)	Release Rate[17] lb/s (kg/s)	LFL Distance ft. (m)	Average LFL Distance ft. (m)
FBR	115 (35)	1,964 (891)	5,497 (1,675)	4,729 (1,441)
	246 (75)	1,057 (479)	3,961 (1,207)	
3-in. (75 mm) leak	33 (10)	158 (72)	1,198 (365)	1,526 (465)
	115 (35)	237 (108)	1,690 (515)	
	227 (69)	242 (110)	1,690 (515)	

Since the depth at which a release could occur can vary based on the location of the failure, the average LFL distance was used as the Potential Impact Radius of NGL releases for each release size (see Table 2-20).

[16]The representative wind speeds are determined using probability weighted average, with the exception of the low wind speed class. 4.5 mph is typically used to represent low wind speed in dispersion modeling.

[17]The release rates used for the 3-in (75 mm) leak scenarios are based on the rates calculated for a 30-in. line. Since the leak involves a relatively small puncture diameter of 3-in (75 mm), it results in an instantaneous drop to choked flow upon rupture, leading to a very slow decompression and almost constant discharge mass rate. Given the very large amount of upstream inventory, the pipeline behaves much the same as an infinite reservoir, and the variation between release rates from a 30-in. and a 20-in. line will be negligible.

As mentioned previously, if the gas cloud on the water surface ignites, there is a potential for high levels of thermal radiation in the surrounding area. Figure 2-27 shows the maximum extent of the 5,000 Btu/h.ft^2 (15.8 kW/m^2) thermal radiation for each wind and stability category. The 5,000 Btu/h.ft^2 (15.8 kW/m^2) is the thermal radiation threshold at which the chance of fatality over a 30-second exposure becomes significant (>1%).

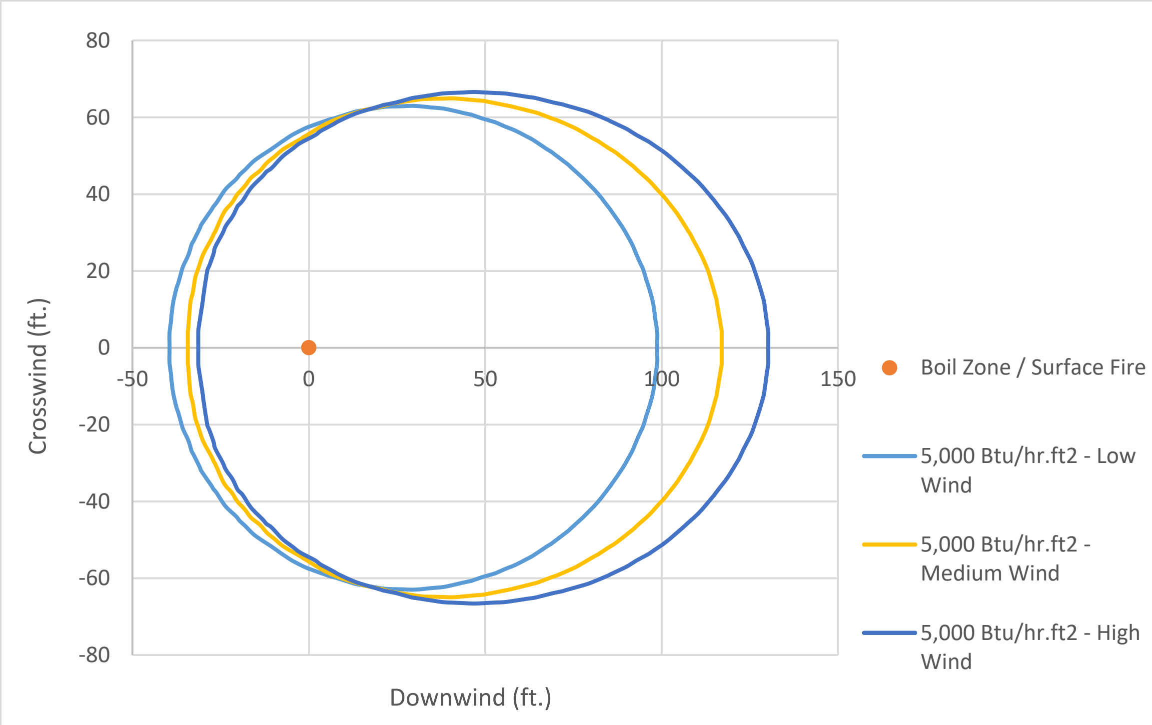


Figure 2-27: 5,000 Btu/h.ft^2 (15.8 kW/m^2) Thermal Radiation Contour

As indicated in Figure 2-27, the extent of the radiation is local to the released location – less than 130 ft. (40 m) for the worst weather category. Since the safety consequence from such an event is not considered significant compared to the area covered by the flammable cloud (Table 2-20), the latter is used as the Potential Impact Radius for the purpose of health and safety risk assessment.

2.4.2.5 Health and Safety Consequence

Line 5 transports both NGLs (primarily propane) and crude oil. While both products exist as liquids at pipeline operating pressures, upon release to atmosphere, NGLs flash to a gaseous phase, whereas crude oil remains as a low vapor pressure liquid.

For a given set of land use and environmental conditions, releases of flammable gaseous products have a much higher ignition probability than releases of flammable liquids [125]. Furthermore, low vapor pressure liquids such as crude oil, which have no flammable cloud beyond the liquid pool are classified as ‘LF1’ liquids. Such LF1 liquids have ignition probabilities that are approximately 0.4% that of flammable gases [123, p. 201]. This difference in susceptibility to ignition between crude oil and NGLs is further enhanced in this particular case due to the behavior of flammable gas clouds. Specifically, in the case of NGL releases, the flammable gas cloud (which is denser than air) has the potential to migrate from the point of release (in this case, water, where the potential for ignition is low) to adjacent areas where sources of ignition may be encountered (in this case, the developed shoreline). In the case of crude oil, on the other hand, this is not the case. This is because, as an LF1 liquid, crude oil does not generate flammable gas clouds that are far-ranging in extent. Consequently, for the health and safety consequence evaluation of Line 5 that is associated with ignition scenarios, NGL releases dominate to a degree that, by comparison, crude oil releases are considered negligible.

Apart from hazards associated with ignition, acute exposure to releases of petroleum products can result in physical health impacts that include headaches, nausea, eye irritation, throat irritation, cough, itchy skin, rashes, shortness of breath and general malaise among those exposed. In the case of the 2010 spill of diluted bitumen from Enbridge's Line 6B into Talmadge Creek and the Kalamazoo River, a total of 145 spill-related visits to health care providers were recorded [126, p. 27]. Nevertheless, the literature shows that in acute exposures of oil spills, most symptoms (97%) are resolved in one week, and that even among clean-up workers, who typically have longer duration exposures, symptoms do not persist over the long term [126, p. 13].

While it is not the intent to minimize the health effects of acute exposure to non-ignited releases, the foregoing discussion is provided to illustrate that the health and safety impacts of a spill from Line 5 are dominated by releases of NGLs. This is because releases of NGLs have the potential to form a flammable gas cloud which, if ignited, can result in a flash fire. By convention, in evaluations of individual and societal risk, individuals who are within the flame envelope of a flash fire are considered to have fatal exposures. As such, the potential for flash fire resulting from ignited releases of NGLs is the dominant health and safety hazard, rendering all other hazards negligible by comparison.

An assessment of the ignition probabilities and the impacted population is included in the following sections.

2.4.2.5.1 Methodology

2.4.2.5.1.1 Failure Mechanism Release Location and Impacts

The calculation of risk is undertaken by relating the probability of a release with its associated consequences. As outlined in Section 2.4.1.1, failure probability has been determined on a threat-specific basis, with each threat being associated with a specific failure mode (3-in. or 75-mm diameter hole, or FBR). For the existing Straits Crossing segments, the threats of anchor interaction and outside forces related to spanning were assigned to an FBR failure mechanism, whereas the threat of incorrect operations was assigned to a 3-in. (75 mm) hole failure mechanism.

Due to the nature of the threats giving rise to full-bore ruptures, which include anchor interaction and spanning in deep water beyond the limits of trenched installation, for modeling purposes, releases generated by these threats were located in the center of the shipping channel. For the threat of incorrect operations, however, which is associated with 3" holes, it was recognized that there is no geographical preference for the locations of these releases. Consequently, for modeling purposes, consequences associated with 3" holes were determined on a length-average basis, by modeling flash fire areal extent at about 200 ft. (60 m) intervals along the entire crossing, and Identifying dwellings contained within each flash fire zone. Counts of individuals associated with each of the identified dwellings were then determined based on an average dwelling occupancy rate of 2.4, per US Census data [127].

2.4.2.5.1.2 Ignition probability

The methodology used for calculating the ignition probabilities for this assessment is based on industry guidelines ([128] and [125]). As shown by these guidelines, for a given scenario, the ignition probability varies with the mass flow rate, and that this relationship can be represented by a relatively simple correlation. *Look-up* tables or correlations for a range of representative scenarios have been developed to provide an easy-to-use reference for ignition probabilities.

Gas clouds from accidental releases from the Straits pipelines are expected to travel mostly over the open water where the ignition probabilities are extremely low. However, in cases where the flammable cloud reaches the shorelines, there is a possibility of cloud ignition. For releases that reach the shore, the following correlation for gaseous releases within rural areas, was determined to be the most suitable.

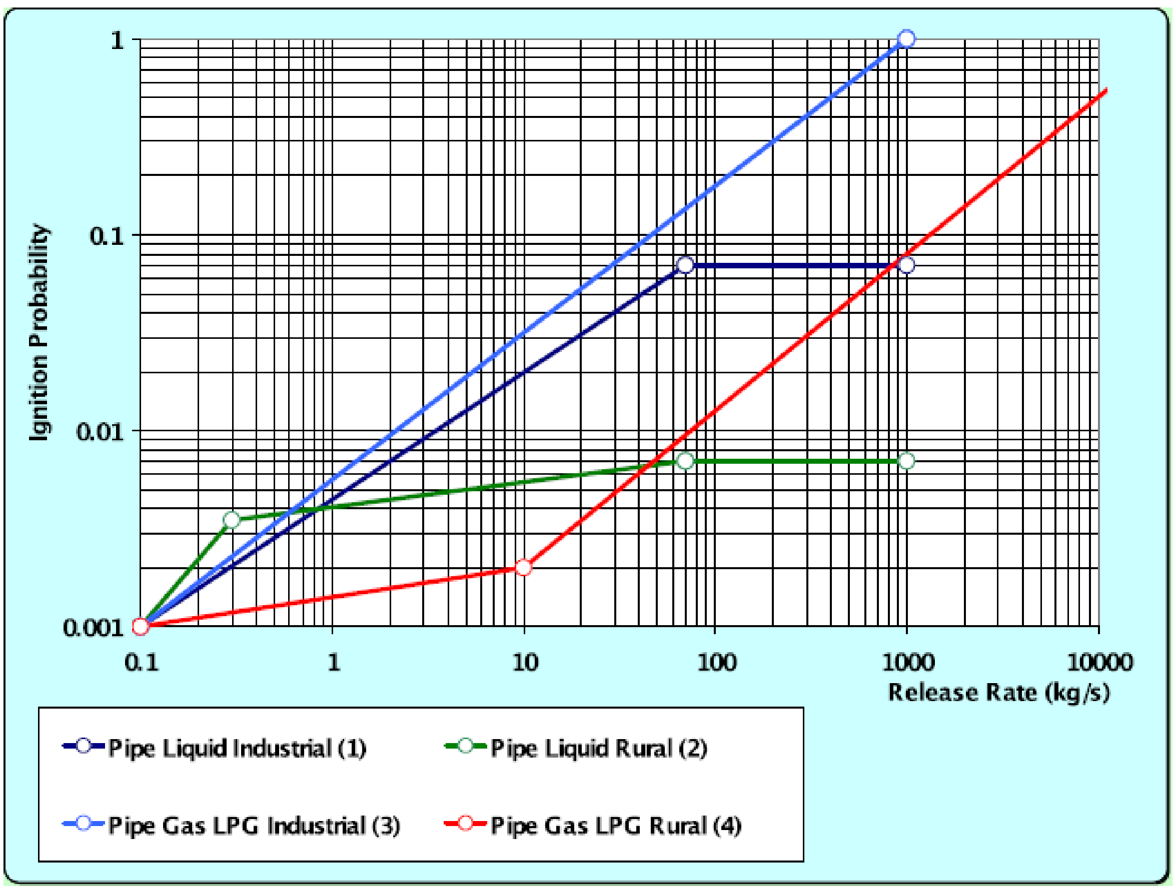


Figure 2-28: Release Rates vs. Ignition Probabilities [128]

Using the correlation for gas releases within rural areas shown on Figure 2-28 (Curve 4) and the discharge rates identified in Section 2.4.2.3, the ignition probability is determined for each release size (see Table 2-21). These ignition probabilities are only applicable in cases where the flammable clouds migrate from water to land.

Table 2-21: Ignition Probability

Release Size	Max. Release Rate lb/s (kg/s)	Ignition Probability on Land
FBR	1,964 (891)	8%
3-in. (75 mm) leak	242 (110)	2%

2.4.2.5.1.3 Hazard Vulnerability

A flash fire is a sudden, intense fire caused by ignition of a mixture of air and a dispersed flammable substance. The general approach to modeling the vulnerability of individuals to flash fire events is to assume that those located within the flame envelope of a flash fire have a 100% probability of fatality and that individuals outside are unaffected [123, pp. 117-123]. Table 2-22 contains a rule-set that has been adopted, assuming the gas concentration at the LFL can ignite and produce a flash fire.

Table 2-22: Flash Fire Vulnerability Criteria

Location	Probability of Fatality
Within lower flammability limit cloud	1
Outside lower flammability limit cloud	0

2.4.2.5.2 Results

To determine the safety impact of the potential flash fires on the surrounding area and the shorelines, the radius of the flammable cloud, for each release size, was superimposed on the Straits area map. Figure 2-29 and Figure 2-30 show the extent of the flammable cloud from releases from both East and West Straits pipelines.

Figure 2-29: Extent of NGL Flammable Cloud from FBR Scenarios

Figure 2-30: Extent of NGL Flammable Cloud from 3-in. (75 mm) Leak Scenarios

As indicated in Figure 2-29, the LFL clouds resulting from a FBR (located within the shipping channel) of the pipeline crossing, do not reach the shorelines or the Mackinac Bridge. Additionally, since the NGLs carried by the Straits pipelines are heavier than air, in case of a failure, the height reached by the flammable cloud will be relatively low, particularly as the cloud travels away from the release point. The implication of this is that, in addition to the paucity of ignition sources on the lake surface, the flame envelope of a flash fire would not have a large enough vertical extent to affect individuals on the deck of a ship. Hence, the LFL cloud resulting from a pipeline rupture is not expected to pose a significant hazard to vessels traveling through the Mackinac shipping channel.

The flammable clouds produced following a pipeline leak could hypothetically reach land provided that such a leak occurred close enough to shore (Figure 2-30). Nevertheless, a review of development on the north shore indicated that there are no structures that would fall inside the flash fire flame envelope caused by a leak, regardless of where that leak might be relative to the shoreline.

On the south shore, however, for leak locations that lie close to shore, the flash fire flame envelope caused by a leak encompasses a number of dwellings.

Table 2-23 summarizes the potential impacts to individuals resulting from flash fires generated by FBRs as well as 3-in (75 mm) holes on both the north and south shores. Table 2-23 shows that, on average, the number of individuals impacted by the East Straits crossing is slightly higher than the number of individuals impacted by the West Straits pipeline. This difference is attributed to a higher number of dwellings and population density on the east side of the crossing on the south shore.

Table 2-23: Safety Impact of NGL Releases

Pipeline	Release Size	Ignition Probability	Max. No. of Impacted Dwellings	Weighted Average No. of Impacted Dwellings	Max. No. of Impacted Individuals	Weighted Average No. of Impacted Individuals
East Crossing	FBR	Extremely Low	N/A	N/A	N/A	N/A
	3-in (75 mm) leak	2%	60	5	144	11
West Crossing	FBR	Extremely Low	N/A	N/A	N/A	N/A
	3-in (75 mm) leak	2%	29	2	70	5

2.4.2.6 Economic Consequence

The economic analysis of the spill costs involves the direct estimation of cleanup costs and a factored estimate for eventual damages. In simplest terms:

Total Spill Costs = Total Response & Clean-up Costs + Total Damage Costs

The response and cleanup costs are a function of factors such as spill remoteness, spill size, amount of onshore oiling, type of cleanup technique used, time of year, and oil density and chemistry. Cleanup costs are also affected by the nature of onshore areas that are impacted by the spill. The damage estimate reflects potential longer term social and environmental costs associated with damages to natural resources, restoration of environmental functions, and impacts on both commercial and subsistence resource harvesting.

The spill cost modeling provides linear and non-linear functions for a number of the factors associated with the spill. The model is based on historical experience with spills in the US and with global maritime spills. The model is particularly appropriate for the estimation of hypothetical spills, as it is based on statistical findings related to global spills over the past three decades. The model excludes fines and penalties associated with a spill event.

2.4.2.6.1 Methodology

The spill cost model structure and common assumptions pertaining to spill costs in the Straits is described are described in Appendix R. The costs are based on the outflows described in Section 2.4.2.1, coastal characteristics of impacted shorelines, and individual characteristics of the 360 spills modeled for the various outflows.

As further described in Appendix R, the consequence of spills within the Straits were determined as a function of release magnitude (leaks and ruptures) and release location. The analysis considered cost impacts associated with several variables, including, time of year (ice vs. no ice), length of shoreline impacted, and the distribution of land-use in shorelines for those counties affected.

The Straits are designated as an HCA in accordance with the regulations established by 49 CFR Part 195 §195.450. Beyond that, the Straits are a culturally significant resource with associated tribal fishing and Treaty rights, and the oil spill factors reflect that by using higher response costs and damage levels.

Within the Straits, the core spill zone includes Emmet, Cheboygan, and Mackinac counties, in which 99% of spill material deposition would occur. The damage estimate reflects potential longer term social and environmental costs associated with damages to natural resources, restoration of environmental functions, and impacts on both commercial and subsistence resource harvesting.

As outlined in Section 2.4.2.1, in consideration of the failure mechanisms associated with both leaks and ruptures, spills caused by ruptures were modeled with a release location in the middle of the shipping channel, while leaks were modeled with release locations closer to both the north and south shores. As discussed in Appendix R, while the contingent environmental damage costs for near-north-shore leaks were different from near-south-shore leaks, the average of these two values were used for risk calculation purposes.

2.4.2.6.2 Results

Based on the analysis described in Appendix R, contingent total economic costs within the Straits were assessed as follows (these costs also *include* the environmental damage costs summarized in Section 2.4.2.7.2:

- leaks: $128,160,000
- ruptures: $103,330,000.

2.4.2.7 Environmental Consequence

As outlined in Section 1.9.5, for the purposes of characterizing and comparing the environmental risk between the various alternatives considered in this report, by convention, the environmental component of economic consequence has been adopted to represent environmental consequence. This measure of environmental consequence is based on a monetization of the damages, which in principle encompass the following impacts, provided that these impacts can be directly associated with a spill event:

- restoration costs of the natural environment
- a broad range of environmental damages normally included within an NRDA, including air, water and soil impacts.
- net income foregone in the sustainable harvest of a commercial resource
- net value foregone in the sustainable harvest of a subsistence resource, including fisheries.

The quantified elements of spill cost reflect an expected value of damages contingent upon the occurrence of an initial spill event.

2.4.2.7.1 Methodology

As further described in Appendix R, the consequence of spills within the Straits were determined as a function of release magnitude (leaks and ruptures) and release location. The analysis considered cost impacts associated with several variables, including, time of year (ice vs. no ice), length of shoreline impacted, and the distribution of land-use in shorelines for those counties affected.

The Straits are designated as an HCA in accordance with the regulations established by 49 CFR Part 195 §195.450. Beyond that, the Straits are a culturally significant resource with associated tribal fishing and Treaty rights, and the oil spill factors reflect that by using higher response costs and damage levels.

As outlined in Section 2.4.2.1, in consideration of the failure mechanisms associated with both leaks and ruptures, spills caused by ruptures were modeled with a release location in the middle of the shipping channel, while leaks were modeled with release locations closer to both the north and south shores. As discussed in Appendix R, while the contingent environmental damage costs for near-north-shore leaks were different from near-south-shore leaks, the average of these two values were used for risk calculation purposes.

2.4.2.7.2 Results

Based on the analysis described in Appendix R, contingent environmental damage costs within the Straits were assessed as follows:

- leaks: $76,900,000
- ruptures: $62,000,000.

These environmental damage costs are *within* the total economic costs summarized in Section 2.4.2.6.2; they are *not* added to the total economic cost.

2.4.3 Risk Calculation

2.4.3.1 Health and Safety Risk

In risk analysis, Health and Safety risk is conventionally expressed as the annual probability of death of a person, resulting from a hazardous event [129, p. 112]. The hazardous event associated with the calculation of health and safety risk for Alternative 5 is a pipeline failure. As outlined in Section 2.4.2.5, it is a pipeline failure that precipitates an ignited release of NGLs.

2.4.3.1.1 Methodology

The probabilities associated with two separate failure mechanisms – FBR and a 3-in. (75 mm) hole (leak) were determined in Section 2.4.1.1.2. Health and Safety Risk ($R_{H\&S}$, fatalities/y) was determined in accordance with Equation 2-17.

$$R_{H\&S} = F_{NGL} \times \left[\left(P_R \times P_{ign,R} \times I_R \right) + \left(P_L \times P_{ign,L} \times I_L \right) \right]$$

Equation 2-17: Calculation of Health and Safety Risk

Where:

F_{NGL} = Fraction of the time Line 5 is assumed to transport NGLs (= 1/6)
P_R = Annual rupture probability (see Section 2.4.3.1.1.1)
P_L = Annual leak probability (see Section 2.4.3.1.1.1)
$P_{ign,R}$ = Probability of ignition associated with a rupture event (8%, per Section 2.4.3.1.1.1)
$P_{ign,L}$ = Probability of ignition associated with a leak event (2%, per Section 2.4.3.1.1.2)
I_R = Weighted average number of impacted individuals from a rupture (see Section 2.4.3.1.1.2)
I_L = Weighted average number of impacted individuals from a leak (see Section 2.4.3.1.1.2)

2.4.3.1.1.1 Annual Leak and Rupture Probability

As summarized in Section 2.4.1.1.2, failure probability for the existing Straits Crossing segments was derived by a threat-based analysis in which the overall failure probability is derived from the following threats and their associated failure mechanisms:

- Anchor Damage: $3.433\text{x}10^{-04}$ per year (rupture failure mode)
- Incorrect Operations: $1.007\text{x}10^{-04}$ per year (leak failure mode)
- Vortex-Induced Vibration: $1.42\text{x}10^{-05}$ per year (2018) (rupture failure mode)
- Spanning: $<1\text{x}10^{-08}$ (beyond resolution of analysis).

The annual probability of rupture within the existing Straits Crossing segments may be determined as the statistical OR calculation of the probability of failure due to anchor damage and the probability of failure of vortex-induced vibration, and is equal to $3.575\text{x}10^{-04}$. The annual probability of leak within the existing Straits Crossing segments is $1.007\text{x}10^{-04}$.

2.4.3.1.1.2 Weighted Average Impacted Individuals

The weighted average number of impacted individuals is defined as the average number of individuals that would be within the flame envelope of a flash fire generated from an NGL release. As outlined in Section 2.4.2.5.2, the weighted average number of impacted individuals for ruptures is zero, owing to the distance between rupture release events and locations of habitation. The weighted average number of impacted individuals for leaks was reported as 11 for the East Crossing and 5 for the West Crossing. Therefore, for the purposes of the risk calculation shown in Equation 2-17, an average value of 8 has been used to represent the weighted average number of impacted individuals.

2.4.3.1.2 Results

From Equation 2-17, the health and safety risk associated with the existing Straits Crossing segments was determined to be $2.69\text{x}10^{-06}$/y.

2.4.3.2 Economic Risk

2.4.3.2.1 Methodology

The probabilities associated with two separate failure mechanisms – leak, and rupture were determined in Section 2.4.1.1.2.

Economic Risk (R_{Econ}, \$/yr) was determined in accordance with Equation 2-18.

$$R_{Econ} = F_{Oil} \times \left[\left(P_L \times \$_{Econ,L} \right) + \left(P_R \times \$_{Econ,R} \right) \right]$$

Equation 2-18: Calculation of Economic Risk

Where:

F_{Oil}	=	Fraction of the time Line 5 is assumed to transport oil (= 5/6)
P_L	=	Annual leak probability (= $1.007\text{x}10^{-04}$ per Section 2.4.1.1.2)
P_R	=	Annual rupture probability (= $3.575\text{x}10^{-04}$ per Section 2.4.1.1.2)
$\$_{Env,L}$	=	Economic impacts associated with a leak in the Straits (= \$128,160,000 per Section 2.4.2.6.2)
$\$_{Env,R}$	=	Economic impacts associated with a rupture in the Straits (= \$103,330,000 per Section 2.4.2.6.2)

2.4.3.2.2 Results

From Equation 2-18, the Economic Risk associated with Alternative 5 was determined to be $41,500/y.

2.4.3.3 Environmental Risk

2.4.3.3.1 Methodology

The probabilities associated with two failure mechanisms – leak and rupture, were determined in Section 2.4.1.1.2.

Environmental Risk (R_{Env}, \$/y) was determined in accordance with Equation 2-19.

$$R_{Env} = F_{Oil} \times \left[\left(P_L \times \$_{Env,L} \right) + \left(P_R \times \$_{Env,R} \right) \right]$$

Equation 2-19: Calculation of Environmental Risk

Where:

F_{Oil} = Fraction of the time Line 5 is assumed to transport oil (= 5/6)
P_L = Annual leak probability (= 1.007×10^{-04} per Section 2.4.1.1.2)
P_R = Annual rupture probability (= 3.575×10^{-04} per Section 2.4.1.1.2)
$\$_{Env,L}$ = Monetized environmental impacts associated with a leak in the Straits (= $76,900,000 per Section 2.4.2.7.2)
$\$_{Env,R}$ = Monetized environmental impacts associated with a rupture in the Straits (= $62,000,000 per Section 2.4.2.7.2)

2.4.3.3.2 Results

From Equation 2-19, the Environmental Risk associated with Alternative 5 was determined to be $24,900/y.

2.5 Evaluation of Safe and Reliable Operating Life

Pipeline integrity can deteriorate over time by the action of time-dependent threats. As was discussed in Section 2.4.1.1.1, in the *Threat Assessment* that was completed on the existing 20-in. Straits Crossing segments, twelve separate threat categories were considered. Each of the twelve threat categories can be characterized as either time-dependent or time-independent; the difference between the two being that the passage of time influences the likelihood of failure for time-dependent threats, whereas the likelihood of failure is not influenced by the passage of time for time-independent threats. The twelve threat categories are presented below, characterized by time dependency:

2.5.1 Time-Dependent Threats

1. External corrosion
2. Internal corrosion
3. Selective seam corrosion
4. Stress corrosion cracking (SCC)
5. Time-dependent failure due to resident mechanical damage
6. Activation of resident damage from pressure-cycle-induced fatigue
7. Weather and outside force (spanning stresses and vortex-induced vibration) (note that while this is not normally considered a time-dependent threat, it is characterized as such in this particular case due to the dynamic loading characteristics associated with the mechanisms involved)

2.5.2 Time Independent Threats

1. Manufacturing defects

2. Construction and fabrication defects
3. Equipment failure (non-pipe pressure containing equipment)
4. Immediate failure due to mechanical damage
5. Incorrect Operations

The *Threat Assessment* performed on the existing 20-in. Straits Crossing segments characterized the following as principal threats (those threats for which an evaluation of susceptibility attributes indicates a significant vulnerability, and that have the potential to provide the most significant contributions to overall failure probability):

- Immediate failure due to mechanical damage;
- Weather and outside force; and,
- Incorrect operations

The remainder of the threats were characterized as secondary threats (threats for which an evaluation of susceptibility attributes indicates a relatively insignificant or non-significant vulnerability and that therefore have the potential to contribute only at a second-order or potentially negligible levels in terms of overall failure probability). The threat attribute review conducted as part of the *Threat Assessment* did not provide any indication that any of the secondary threats might become principal threats at some point in the future; particularly if Enbridge's current maintenance and assessment practices are continued.

As described in Section 2.4.1.3, of the three principal threats, only for the threat of vortex-induced vibration does failure probability change with time, increasing from 1.42×10^{-05} to 1.61×10^{-05} over the time span from 2018 to 2053. This increase in failure probability of 0.19×10^{-05} represents an increase of only 0.4% in the combined (All Threat) failure probability over this time frame. Therefore, time does not represent a significant factor in the failure probability estimates derived for the Straits.

Metallurgical Considerations of Time Dependency

Apart from the action of time-dependent threats, time-temperature reactions are possible at sufficiently high temperatures, and can cause changes in steel properties under such circumstances. The working stress design (WSD) philosophy adopted in U.S. design codes is based on elastic response under design conditions, and assumes that material design properties remain constant over the operational life of the pipeline. Therefore, the constancy of these properties is essential to assure long-term integrity. Key parameters in WSD include steel stiffness (termed 'Elastic Modulus', E), and the proportional limit of the line pipe material (termed 'Specified Minimum Yield Stress', or SMYS). Under the design philosophy adopted by U.S. design codes, a design factor is applied to ensure that operating stresses remain below an established fraction of SMYS. This design factor provides a margin of safety against unforeseen loading conditions or the presence of flaws. Apart from steel properties that are associated with WSD, another property that is important to the maintenance of pipeline integrity is fracture toughness, which, in the presence of a flaw, plays a role in preventing fracture initiation.

There are several mechanisms by which the physical properties of metallic materials can change over time. Most, however, such as high-temperature creep and temper embrittlement, involve temperatures that are well above the operating limits of transmission pipelines. Strain aging is one process that can occur at temperatures associated with pipeline operating temperatures. Strain aging is caused by the accumulation and deposition of solute atoms (typically carbon and/or nitrogen) at locations of irregularities in a steel crystal lattice (known as 'dislocations'). This locking of dislocations, which is a fundamental aspect of the strain aging process, manifests itself as an increase in hardness and yield strength. [130, p. 346] In order for strain aging to occur, a metal must be exposed to sufficiently high strain to cause deformation, followed by a sufficiently long enough period of time at a sufficiently high enough temperature to enable solute atoms to migrate through the crystal lattice and to accumulate at dislocations. The kinetics of diffusion are influenced by both time and temperature, such that the higher the temperature, the faster the rate of diffusion, and hence, the faster the rate at which strain aging will occur.

The plastic strain necessary to promote strain aging must occur below forging temperatures, and in line pipe, this can occur during pipe forming, cold field bending, and it can also be caused by local flow associated with welding residual stresses. It should be noted, however, that for seamless pipe, such as is associated with the 20-in. Straits Crossing segments, pipe forming is performed at forging temperatures; also, cold field bending was not employed during the installation of the Straits Crossing segments.

Numerous studies and experiments have been conducted to characterize the effect of strain aging on steel material properties. Typically, these experiments have been conducted at high temperatures (well above the operating temperature range experienced by most transmission pipelines) in order to accelerate the strain aging process. A study undertaken by Battelle Memorial Institute, commissioned by the Interstate Natural Gas Association of America in conjunction with the American Gas Foundation evaluated the accumulated knowledge of the effects of strain aging on pipeline integrity ("the Battelle Study") [61] (Appendix C).

In the presence of a defect, fracture initiation occurs in a quasi-static manner; the Battelle Study found:

No measure or surrogate for quasi-static initiation resistance was found to be degraded due to aging at 250°F, which is an upper-bound to temperatures that might be experienced in pipelines.

It furthermore found:

Initiation resistance characterized in reference to both ductility (reduction in area) and CVN USE* were both invariant of aging at 250°F. Therefore, in reference to fracture initiation, strain aging can be anticipated to have a minor effect if any…It follows that aging constitutes a comparatively minor influence, with any change due strain aging being a second order effect with little practical influence on fracture initiation and propagation behavior.

With respect to the potential influence of strain aging on modulus of elasticity (which is central to pipeline design), the Battelle Study noted that this property:

…is determined by atomic binding forces and the crystalline structure of the material involved…these binding forces and crystallography cannot be changed without modifying the basic nature of the steel. For this reason, within a given class of materials such as steel, the elastic modulus is among the most microstructure invariant mechanical properties.

* Charpy V-Notch Upper Shelf Energy is a measure of toughness

In that respect, strain aging does not have an effect on elastic modulus.

The Battelle Study concluded:

These results lead to the conclusion that aging is unlikely to be a factor in the performance of vintage pipelines.

Regarding design parameters that underlie WSD as used for pipelines, this review indicates that strain aging does not adversely affect the design basis, as follows:

- The elastic modulus remains a constant for normal gas pipeline operating conditions, and;
- The yield strength increases with aging during the initial steps and may decrease later in the process but not below initial levels

3 Alternative 4

3.1 General Description

This Alternative considers the replacement of the existing twin 20-in. Straits Crossing segments with a new pipeline crossing that utilizes the best available design and technology.

Two options are considered:

1. a conventional replacement, which utilizes current state-of-the-art offshore technology to design, construct, and install a pipeline, buried in a trench through the length of the Straits Crossing; and,
2. a Straits Crossing pipeline that is installed in a tunnel with sealed, concrete walls.

3.2 Alternative Technologies and Designs

To replace the two 20-in. diameter pipelines which currently cross the Mackinac Straits, a single 30 in. outer diameter pipeline will be used. Initially the dual 20-in. pipelines were installed to add redundancy to the crossing in case one line required shut-down for maintenance activities. Dual pipelines will not be considered for this option as contemporary crossing methods, materials, and protection systems will greatly reduce any risk of pipeline failure.

Two installation alternatives were evaluated to install a new crossing

- Conventional Crossing - This considers new, 30 in. diameter crossing pipeline, coated with concrete and installed within a trench dug into the Mackinac Straits lakebed
- Tunnel Crossing – Vertical launch and retrieval shafts would be constructed into the bedrock on either side of the Mackinac Straits and a tunnel, containing the pipeline, would be constructed in the bedrock underneath the Strait

3.2.1 Alternative 4a - Conventional Replacement

A conceptual design of the conventional replacement trenched pipeline crossing was developed, incorporating modern marine pipeline industry technology.

It is important to note that this conceptual design is primarily based upon available public domain data. No project specific surveys were available. Route surveys, bathymetry surveys, geotechnical core sampling, current velocity measurements, onshore surveys etc. are anticipated to be completed together with the next phases of design and may result in changes to the concept design described herein.

3.2.1.1 Pipeline Route

A straight-line route across the Straits was assumed, adjacent to and west of Enbridge Line 5.

Several crossing routes were found to be feasible within an area at the neck of the Straits, west of the Mackinac Bridge and east to the east edge of the designated “Cable and Pipeline Area" indicated on the marine chart in Figure 3-1 below. Confining potential crossing routes to this area minimizes the crossing length and imposes no additional burden on shipping operations being adjacent to existing pipeline and cable crossings.

A preferred centerline has been identified, described by a straight line connecting the shoreline points as shown in Figure 3-1.

This centerline provides a technically feasible crossing route with potentially adequate land available on the north shore for pipe stringing operations and on the south shore for pipe winching operations. However, no onshore reconnaissance, onshore surveys, offshore surveys, or land ownership investigations have been performed as part of this analysis. These would be required to confirm and finalize such a pipeline route. Proximity to, and potential interference with, existing offshore cables requires further assessment since not all cables are individually identified on the marine chart. If interference with existing offshore cables is revealed, the proposed pipeline crossing may be re-located slightly farther to the west.

The crossing route, approximately 4.1 mi. (6.6 km) in length, is shown superimposed on the marine chart in Figure 3-1.

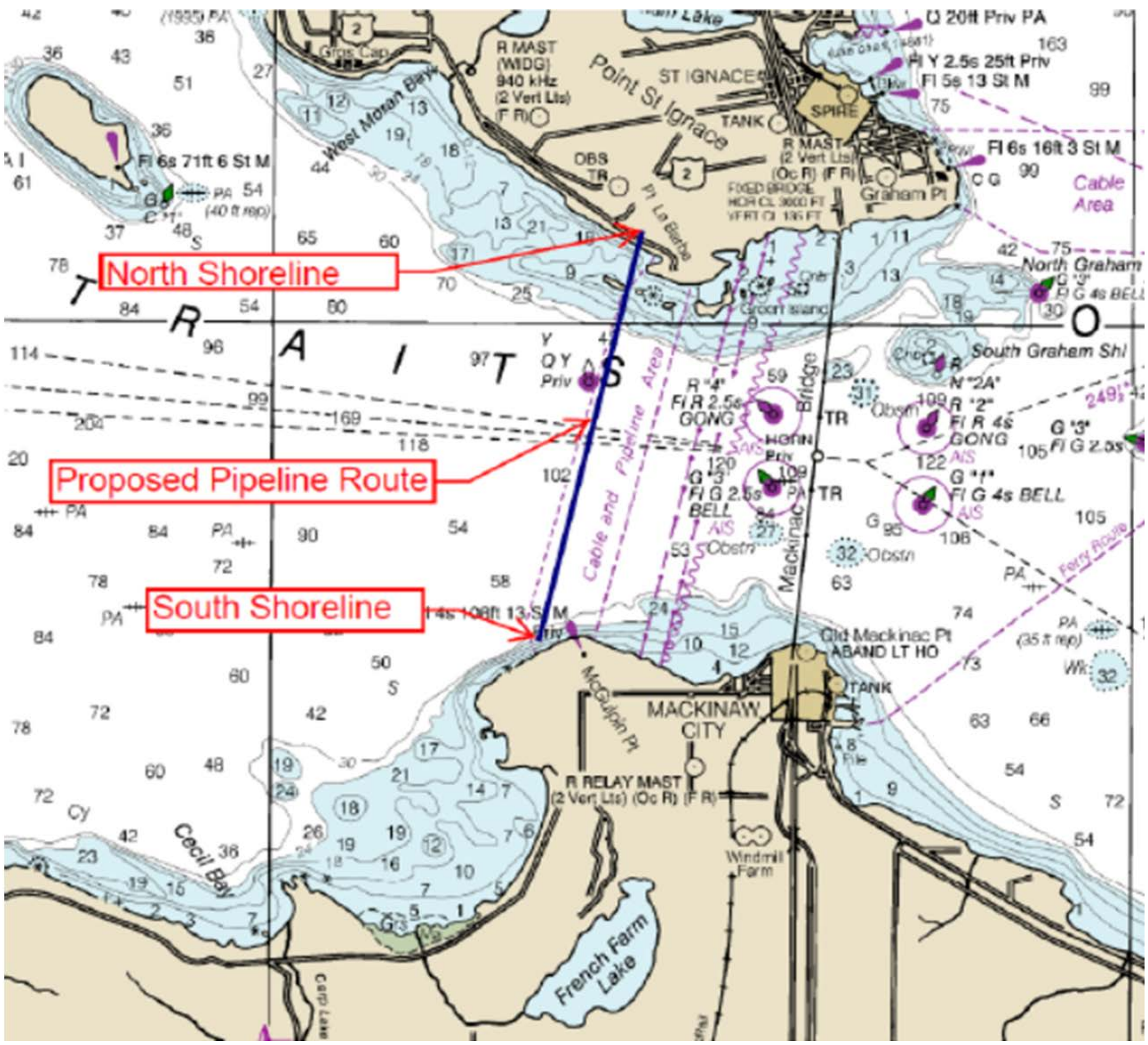


Figure 3-1: Conventional Crossing Route on Marine Chart

An approximate bathymetric profile of the proposed crossing centerline was developed for illustration as shown in Figure 3-2. This profile is based on the current Line 5 pipeline crossing profile with the determination provided in Figure 3-2. A water elevation of 176 m is assumed based on the average of annual data.

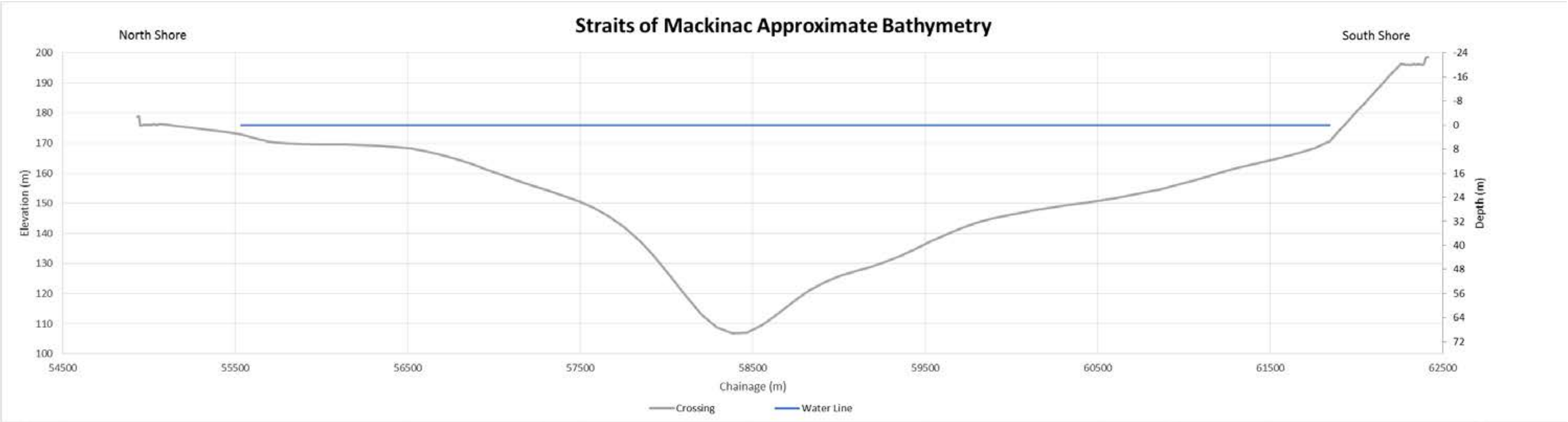


Figure 3-2: Approximate Bathymetry Profile

The bathymetric profile shown in Figure 3-2 is not to scale and has been vertically exaggerated to show the mid-point trench. The maximum depth of the crossing is 227 ft. (70 m) at the bottom of the trench.

The Geotechnical Assessment of the Straits (see Attachment 3 in Appendix S) provides a comprehensive review of the available geotechnical data. The main surficial geology units in the Straits identified by Melhorn (1959) from drilling include lacustrine silt and clay, glacial till, outwash deposits (sand, boulders) and sandy clay (possibly till). The surficial deposits on the south side of the Straits show good correlation to beach deposits associated with ancient lake levels. Information about lake bottom deposits from underwater surveys and mitigation records indicates a general trend of sand and clay at screw anchor locations below about 100 ft. depth, and clay and sandy clay above about 100 ft. depth. There is evidence of some boulders and cobbles on the lake bottom near the pipelines. Detailed public domain geotechnical information for the upper 2 m of lakebed is unavailable and so it is assumed for the proposed crossing location that there is minimally to reasonably competent sand/clay mix, occasional boulders, and no bedrock. This assumption is developed assuming that loose/soft lakebed material in the crossing area has been scoured away by the relatively high oscillatory currents and deposited at deeper water locations to the west and east. This assumption will be validated during detailed design.

Lakebed geotechnical data is critical to the trenching assessment and to the dragged anchor analysis. Should a conventional crossing be pursued, collection of project specific / site specific geotechnical data at the crossing location is imperative.

The wave and current data for this crossing location are listed below:

- Maximum wave height, 5-year return period: 15 ft. (4.6 m), Ludington MI[18]
- Maximum wave height 100-year return period: 30 ft (9.1 m), Ludington MI[19]
- Maximum steady current (excluding wave induced): 2 ft/s (0.6 m/s)[20,21]

Steady current is deemed to include oscillatory effects, but exclude the wave induced component. Wave and current data is used to investigate the lateral stability of the pipeline immediately after installation but before completion of trenching, a time period considered to be less than one month. To avoid over conservatism, a one-year return period wave in combination with a measured current velocity of 0.6 m/s is selected. This current velocity is slightly less than the maximum value predicted by the hydrodynamic model provided in Attachment 2 (see Appendix S).

3.2.1.2 Pipeline and Facility Design

3.2.1.2.1 Pipeline Material and Wall Thickness

Longitudinally welded carbon steel manufactured to API 5L-X65 is adopted for this concept design.

[18] *Wave Height and Water Level Variability on Lakes Michigan and St Clair*, Great Lakes Coastal Flood Study, 2012 Federal Inter-Agency Initiative, US Army Corps of Engineers, Melby, JA, et al. Oct 2012.

[19] See previous footnote.

[20] *Current Flow Through the Straits of Mackinac*, NOAA, Great Lakes Environmental Research Lab, Ann Arbor, Michigan, Saylor, J & Miller, G, 1991

[21] *Hydrodynamic Input Data for Stantec (ADCP measured current velocity data)*, Pans, S. Email communication, 17 Dec 2016

The pipeline design pressure for the existing crossing is 600 psi, but 700 psi was selected to match the adjacent onshore pipeline, allowing for consistent operations. Based upon the ASME B31.4 design code and design pressure, pipe wall thickness required for pressure containment is only 0.224 in. (5.7 mm).

However, given the critical nature of this pipeline, a conservative allowance of approximately 0.590 in. (15 mm) is added to account for internal corrosion allowance, external corrosion allowance, mechanical damage resistance, and resistance to external loads. Note that this is consistent with the added wall thickness margin provided on the existing Line 5 crossings. This results in a conceptual design wall thickness of 0.812 in. (20.6 mm) – this wall thickness also allows for a 2-in. (50 mm) thick concrete coating layer to be added to the pipe whilst retaining reasonable negative buoyancy. This concrete coating, discussed below, adds stiffness and weight to the pipe which balances the opposing requirements of lateral stability (the resistance to lateral movement of the pipeline) and installation winch force.

3.2.1.2.2 Pipeline Coatings

3.2.1.2.2.1 External Anti-Corrosion Coat

Three-layer polyethylene (3LPE) is adopted as the external anti corrosion coating for the purposes of this conceptual design. This is a superior pipeline coating to those typically applied at the time of Line 5 installation. The three layers are: fusion bonded epoxy (FBE), a bonding layer, and an outer layer of polyethylene.

Cathodic protection, imposed on the pipeline to prevent corrosion, will supplement this external coating. No interference is expected between the cathodic protection system and external coatings.

3.2.1.2.2.2 External Concrete Coating

The conceptual pipeline design includes an external, welded cage reinforced concrete coat of 2-in. thickness over the 3LPE anti corrosion coating. This coating has several functions:

1. Weight coating to provide on-bottom stability of the pipeline
2. Protect the anti-corrosion coating during installation
3. Protect the anti-corrosion coating during the operational life, and
4. Provide additional mechanical protection in the event of external impact

Offshore pipeline concrete coatings typically employ either medium-density or high-density concrete of 140 lb/ft^3 and 190 lb/ft^3 respectively. Both concrete densities were investigated for this work, high density being used in more critical stability regions (e.g., areas of higher currents). This will require more investigation during Detailed Design.

Resultant pipeline weight values used for this analysis, for medium density and high density concrete respectively, are as follows:

- In-Air Weight (empty) 461.6 lb/ft. (687 kg/m) and 530.8 lb/ft. (790 kg/m)
- Submerged Weight (empty) 63.2 lb/ft.(94 kg/m) and 132.4 lb/ft.(197 kg/m)
- Submerged Weight (hydro-test) 337.3 lb/ft. (502 kg/m) and 406.5 lb/ft.(605 kg/m)

3.2.1.2.3 Pipeline Spanning and Scour

It is proposed to eliminate spanning of the proposed replacement crossing pipeline by trenching/burial of the pipeline. Protection of the pipeline from dragged anchors (discussed in Section 3.2.1.2.4) requires that the pipeline depth of cover be 3.3 ft. (1.0 m), and this depth is considered to adequate to eliminate pipeline spanning.

The existing Enbridge Line 5 pipelines originally laid on the lake bottom for most of the crossing length are subject to span formation, which creates an ongoing maintenance requirement. The resulting disturbance to the oscillatory bottom current flow due to the presence of the pipelines is considered the primary cause of local scour leading to span progression. Evidence from review of available data suggests that span progression could be influenced by uneven pipe bottom contact at the lakebed associated with an irregular lakebed profile along the alignment at the time of the original pipeline installation. This disturbance should be eliminated with a properly installed trenched design.

The proposed installation sequence (discussed in Section 3.2.1.2.5) of the replacement crossing pipeline is:

- Pre-trench shallow water sections (to 100 ft. water depth)
- Install pipeline by winch pull
- Complete the trenching operation (post-trenching)

A preliminary spans analysis indicates that unacceptable spans may be present during the short period after pipeline installation and prior to completion of the post-trenching operation. This may be dealt with by pre-jetting of route high points or post jetting following the as-installed survey.

Annual survey of the trenched/buried pipeline is recommended to confirm no span formation occurs during the operational life of the replacement pipeline. Remedial action such as spot dumping of rock would be used to correct these spans. The frequency of this action is estimated to occur every 5 or so years depending on the actual installation and lake bottom material encountered.

3.2.1.2.4 Anchor Damage

Worldwide pipeline failure statistics reveal that damage due to contact with ship anchors is a credible threat to submarine pipelines. For a replacement trenched pipeline crossing to be demonstrably more robust and reliable than the pipelines it is intended to replace, further consideration of the potential anchor threat is warranted. Two anchor damage events are possible: dropped anchor events and dragged anchor events. The dragged anchor event is focused on as the dropped anchor case is several orders of magnitude less likely to contact a pipeline.

Protection of pipelines from damage by dragged ships anchors is typically achieved by either pipeline trenching and burial, or by placement of a rock berm along the length of the pipeline, or a combination of the two methods. The selected method will depend upon anticipated anchor size and weight, seabed (or lakebed) geotechnical conditions and corresponding anticipated anchor penetration into the bed.

A rock berm works by applying an upward force component on the anchor wire or chain and raises the anchor out of the strike zone. A berm could provide additional protection to the pipeline, but does not provide absolute protection unless it has significant height. Rock berms of this scale are expensive and an adequate level of protection may be achieved without them. Placing the rock berm across a critical area such as the shipping lane is also not practical as an out of control vessel may not stay in the shipping lane while dragging its anchor.

For the Mackinac crossing, trenching and burial would be more practical and cost effective than a rock berm, subject to an assessment of its effectiveness.

An analysis of the susceptibility of a trenched replacement pipeline to failure due to anchor drag is provided in Section 3.5.1.1.2.1. This analysis indicated that a trenched pipeline burial with a minimum depth of cover of 3.3 ft (1.0 m) provides adequate protection from all anchor interaction scenarios other than those that involve fully-seated anchors.

3.2.1.2.5 Crossing Installation Techniques

3.2.1.2.5.1 Installation by Surface Pipe-lay Vessel

At over 4 mi. (6.4 km) in length, the Straits crossing is potentially installable by S-lay, using either a flat bottom lay barge or a “ship-shape” pipe-lay vessel. S-lay involves welding of the pipeline in the horizontal plane on the deck of the lay vessel, and lowering the pipeline under tension to the seafloor in an S-shape.

To mobilize to the crossing location (from the North Atlantic) the barge/vessel must transit the St. Lawrence Seaway, and a total of nine locks. The maximum vessel beam (width) for this transit is limited to 77 ft. (23.8 m)[22].

S-lay barges and S-lay vessels are typically wide of beam and a review of the worldwide fleet indicates only three vessels that could potentially navigate the St. Lawrence Seaway to the Mackinac Straits.

The three vessels are; the EMAS AMC “Lewek Centurian,” the “Hyundai 289,” and Saipem’s “SB 230.” All three are non-U.S. vessels.

The SB 230 has a reported tension capability of only 25 tonnes, inadequate to install a concrete coated crossing pipeline, therefore leaving only two candidate vessels.

A further obstacle to the use of these vessels is potential complication arising from the Jones Act, which restricts access of non-U.S. transportation vessels into the Great Lakes and may impact support vessels, if not the lay vessel itself.

For a relatively small pipeline installation contract, two candidate S-lay vessels, and therefore two bidders, is unlikely to yield a competitive installation cost.

Pipeline reel vessels are another option which tend to be narrower of beam than S-lay barges/vessels. However, installation of rigid pipelines by reeling is typically limited in diameter to 14-18 inches at a maximum. Reel Installation is therefore not considered further.

J-Lay involves fabrication of the pipeline in the vertical orientation, with sections of pipe lowered to the seafloor under tension in a J-shape. J-lay vessels are also unsuitable due to high cost, large size and the relatively shallow water of the Straits.

Installation by surface pipe-lay vessel is not considered further.

[22]greatlakesseaway.com website

3.2.1.2.5.2 Vessel Tow/Winch Installation Methods

Four vessel tow/winch methods have historically been employed for short marine pipelines:

1. **Surface Tow**. Temporary buoyancy is added to the pipe string allowing it to float. It is then pulled by a tug, work vessel, or winch and once in position the pipe is deployed to the seabed by controlled flooding of the pipeline or buoyancy removal. This method is very sensitive to wind and wave action and generally requires a benign weather window of sufficient predicted length of time for the pull. This method is considered unsuitable for the Straits, which experiences high vessel traffic.
2. **Controlled Depth Tow**. This method is similar to the surface tow except the pipe string is negatively buoyant and its depth during towing is controlled by the tension applied. Controlled depth tow is less sensitive to weather than the surface pull, but requires precise coordination between the two vessels. This method is not well suited to winch installation.
3. **Off-Bottom Tow**. The pipe string is held off bottom by a meter or so, controlled by a combination of temporary buoyancy and chains attached to the underside of the pipe string at intervals. Excess chain drags along the bottom, reducing the downward force on the pipe and controlling the height the pipe is maintained off the bottom. This method is less sensitive to weather than surface or controlled depth tow, requires less precise tow vessel operations, and less pull force is required than bottom tow/pull.
4. **Bottom Tow/Pull**. The pipe string is simply dragged along the seabed. Concrete coating protects pipeline during the installation. The tow forces required can be high, but temporary buoyancy may be added to reduce pull forces. The tow route requires a survey prior to installation to determine potential obstructions.

3.2.1.2.5.2.1 Installation by Vessel Tow

Installation of short offshore pipelines by vessel tow has been performed on a number of projects, although lay barge installation is by far the dominant technique.

However, installation by vessel tow is not without risk, as a small number of failures have occurred resulting in loss of the towed pipe string. The main advantage of vessel tow installation is that the vessels used are significantly less costly than specialized lay barges.

The towed pipeline must be winched toward one bank to complete the installation, or a mid-point, offshore tie-in must be performed, both of which add cost and complexity. This is a significant hurdle with respect to a Straits crossing, irrespective of which vessel tow option is considered. Consequently, a vessel tow installation will not be considered further.

3.2.1.2.5.2.2 Winch Pull Installation

Employing a large winch, on shore rather than on vessel, and simply pulling the pipe string across the Strait, is a viable and feasible option.

Suitable winches with pull forces up to approximately 1000 tonnes are available, although lower pull force requirements would increase the number of winches and contractors available, thus potentially reducing the cost.

To successfully implement a shore based winch pull installation it becomes necessary to minimize the pull force required.

The Mackinac Straits replacement pipeline crossing must meet certain design requirements to ensure the replacement pipeline will be robust and reliable; primarily minimum wall thickness and concrete coating thickness, established earlier as 0.812-in. and 2-in. thick respectively. This results in a static pull force of approximately 1200 tonnes, which is considered too high for a practical winch pull operation. Thus, additional temporary buoyancy modules, providing approximately 300-400 tonnes of net buoyancy, are required to be attached to the pipe string to achieve a practical winch force requirement. The final optimization between added buoyancy and winch force would be determined by the winch pull contractor.

The addition of temporary buoyancy to the entire pipe string does introduce some drawbacks:

- Added cost of buoyancy modules
- Removal of buoyancy requires divers or remotely operated vehicles (ROVs) which increases cost and complexity
- The buoyancy would attract additional current loading thus reducing its effectiveness

Nevertheless, on bottom winch pull using added temporary buoyancy is deemed the most practical technique.

Pre-trenching will be accomplished before the bottom winch pull to provide some shielding of the installed pipeline from current induced forces. Pre-trenching will be susceptible to natural backfilling in the period between trenching and pipeline installation. Several pre-trenching methods are available and final selection depends upon further investigation of near surface geotechnical conditions and discussion with trenching contractors. Pre-trenching is discussed further below.

The following additional actions should be considered to further enhance winch pull success:

1. Winch pull should be performed during a predicted favorable weather window to minimize exposure to on-bottom currents
2. A positively buoyant tow-head should be used to lift the leading pipe string section. This will reduce pipeline drag and prevent “dig-in” of the leading section of the pipe string
3. Fabrication of pipe strings should be completed on rollers on the launch bank
4. Consideration should be given to installing temporary rollers on the receiving bank, up to the winch location
5. The pipeline should be flooded, together with the internal cleaning and gauging operation, immediately upon completion of the winch pull
6. Limited pre-trenching should be performed to improve lateral stability during the pull operation

In summary, a Straits crossing by means of a direct on bottom winch pull from onshore is feasible, relatively low risk and cost-effective.

3.2.1.2.6 Pipeline Trenching and Burial

The replacement Straits pipeline crossing requires burial to a minimum target depth of 3.3 ft. (1.0 m) to top of pipe along its entire crossing length to provide protection against anchor damage. Natural backfill from the surrounding native material and consolidation is expected to occur within a few seasons given the relatively high oscillatory currents present. Alternatively, there are methods to mechanically backfill the trench; these options can be investigated during detailed design.

Deeper trenching is required at the very near-shore to a water depth of approximately 30 ft. (10 m). This deeper trenching provides protection against bank erosion, third party interference and, most importantly, ice scour, and this may be accomplished using a barge mounted long-reach excavator prior to pipeline installation. The precise depth of this near-shore trench is dependent upon near-shore topography/bathymetry (not available at this time), but it will likely be in the range of 16 ft. (5 m) deep.

Pre-trenching of the route from the near shore trench to a water depth of approximately 100 ft. (31 m) is required to provide lateral stability of the pipeline during and immediately after installation. This requirement is determined based on preliminary lateral stability analysis taking account of steady and wave induced current acting at lakebed level. Pre-trenching requirements are minimized to the extent possible since this is potentially a less efficient operation due to the likelihood of trench in-fill before pipeline installation.

Additional localized removal of high spots along the route prior to pipeline installation is required to prevent unacceptably long pipeline spans occurring immediately after pipeline installation. Four such locations are identified from the preliminary analysis, to be confirmed by project specific bathymetric survey results. It should be noted that the spans referenced here are lengths of pipe initially unsupported in the trench (during construction only).

Once the pipeline is installed, post installation trenching is performed along the entire length to lower the pipeline to the 3.3 ft. (1.0 m) depth to top of pipe identified as necessary by the preliminary dragged anchor penetration probability analysis. For the purposes of cost estimating this is assumed to require two passes of the trenching spread. It is possible that the minimum trench specified may not be achieved at certain locations of the route. Localized rock or gravel dumping may be deployed to achieve adequate protection in those areas and such a contingency is included in the capital cost estimate.

A number of techniques are typically employed for offshore pipeline trenching, including tracked mechanical cutting, towed plows, and various jetting techniques.

The optimum technique is typically selected in consultation with offshore pipeline contractors once the trench specification is finalized and detailed project and site-specific geotechnical data is available. For the purposes of this study a jetting technique is assumed for both pre-and post-trenching operations. Ploughing is also likely a viable technique, with costs expected to be similar to jetting.

3.2.1.2.7 Pipeline Pigging Facilities

Protection of the replacement pipeline against internal corrosion requires regular pigging of the crossing, to sweep any accumulated water from the low point of the crossing and to allow inspection of the pipeline for internal and external corrosion.

Each existing 20-in. crossing pipeline has a pig launcher on the north side of the Strait and a pig receiver on the south side of the Strait. It is assumed that these will be replaced by a single, 30 in. diameter launcher on the north side and receiver on the south side, located within the current pigging facilities site.

Since pigging of the critical Strait crossing pipeline will likely be more frequent than for the main onshore pipeline, dedicated launcher/receiver facilities are warranted, rather than utilizing an existing upstream launcher and downstream receiver located more distant from the crossing.

The cost of providing new pigging facilities for the replacement 30 in. crossing, within the existing pigging facilities site on each side of the Strait is included in the capital cost estimate.

3.2.1.2.7.1 Bathymetry and Pipeline Pigging

After construction, a baseline bathymetric survey will be conducted along the pipeline route. This may be combined with future surveys to ensure the pipeline does not become exposed due to scour or changing currents within the Straits.

Additionally, a caliper pig with an IMU and MFL capabilities will be run through the pipeline. This pig will check for defects such as dents, ovalities and cracks along the pipeline, providing a baseline for future tool runs.

3.2.1.3 Cost Estimate

The detailed assumptions and costs used to develop the Class 5 cost estimate for this alternative are shown in Appendix H. The estimate has been built up from typical task day rates and estimated completion times, factored pricing for major material items, and percentage based costs for engineering, external consultants and support costs.

In addition to the scope of conventional crossing installation, costs for the new pigging facilities, tie-ins to Line 5, and pipeline segments to the new crossing location are also included within this estimate.

Abandonment of the existing dual 20-in. pipelines crossing the Mackinac Straits has been included in the estimate. The lines will be filled with water and abandoned in place. The abandonment costs are based on the Canadian National Energy Board (NEB) Abandonment Cost Estimates document MH-001-2012. Assumptions for the crossing abandonment can be found in detail in Appendix I.

The major cost categories and overall cost are shown in Table 3-1 below.

Table 3-1: Alternative 4a – Conventional Cost Estimate

Cost Category	Alternative 4a Conventional Crossing
New materials and transportation subtotal	$10,023,000
Construction, support services and abandonment subtotal	$12,546,750
Engineering and external consultants subtotal	$4,716,000
Total project cost	$27,285.750

These costs include an allowance for 1.6 ft. (0.5 m) of rock cover over the top of the pipe along 10% of the route to account for discrete locations where trenching depth of cover is not achieved. Further rock dumping may be required as a remedial action should scour occur over the life of the pipeline. While this practice is not currently employed along the existing Line 5, it should only be necessary once every 5 or so years.

The other operational costs will be similar in scope and magnitude to those for the existing Line 5 pipeline crossings and thus no operational cost analysis was completed for this option.

3.2.2 Alternative 4b - Tunneling Replacement

The purpose of the deep rock tunnel option for crossing the Mackinac Straits is to provide the minimum length, diameter, depth, and service requirements for the 30 in. diameter, welded steel pipeline to transport products currently supplied by Line 5. No alternative designs for including additional utilities within the tunnel are considered since the details of those designs would be affected by the number and types of co-installed facilities. This will maintain consistency in evaluating the conventional crossing option, Alternative 4a - Conventional Replacement.

A detailed discussion of tunneling feasibility, methodology, and construction techniques, including risks of multi-use tunnels can be found in Appendix E.

3.2.2.1 Tunnel Route and Methodology

Routing of the tunnel consists of selecting the shortest practical route across the Mackinac Strait between Mackinaw City to the south and St. Ignace to the north as shown on Figure 3-3.

The shoreline sites selected also considered the potentially available undeveloped land closest to the shore as the exploration program will require material and personnel transport to and from a drilling barge across the straits, and the development was near potentially existing power utility lines. Refer to Appendix E for more detailed views of the shoreline locations.

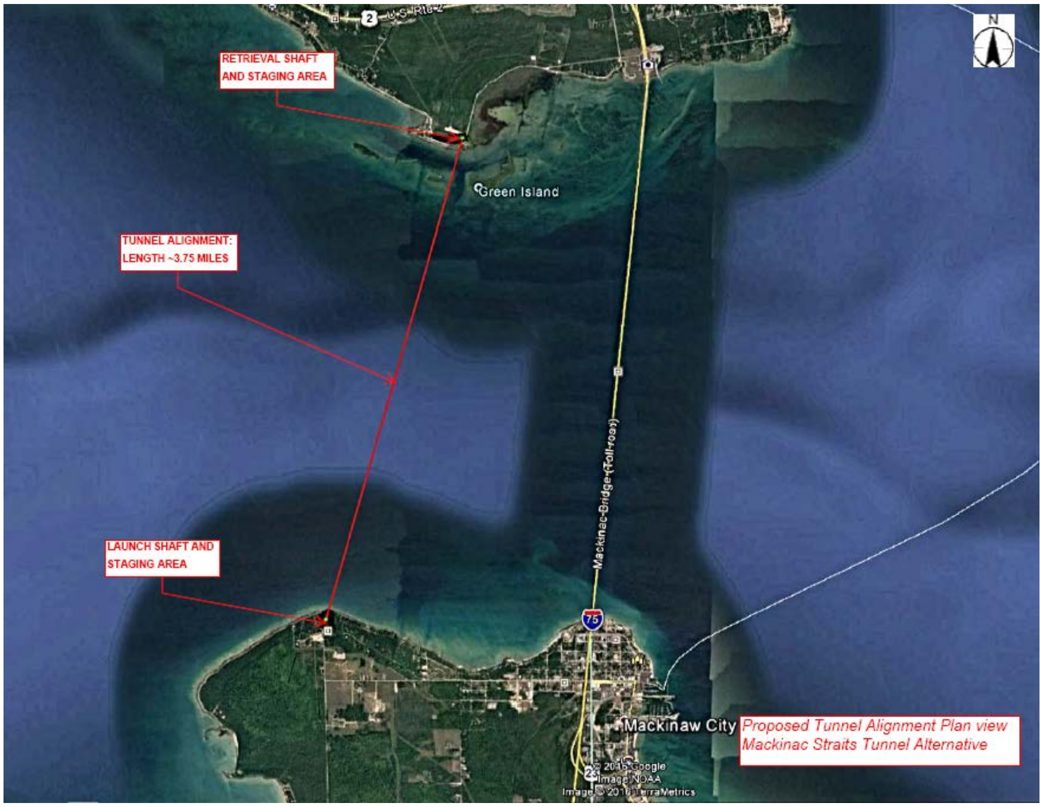


Figure 3-3: Proposed Tunnel Alignment

Good rock conditions and minimal water inflow are anticipated at the Straits and no adverse geotechnical conditions are known to exist which would negate tunneling as an option. These geotechnical conditions are discussed further below. A single- or double-shielded tunnel boring machine (TBM) with a segment erector and with grouting ahead capabilities is the most practical approach with respect to the construction risk, and post-construction risk for the pipeline.

3.2.2.2 Geotechnical Considerations

The discussion in this section is based on the geotechnical report titled, “Independent Alternatives Analysis for the Straits Pipeline Geological Model,” dated 28 November 2016, contained in Attachment 3 (see Appendix S). A preliminary geological interpretation of the tunnel conditions has been developed. The geotechnical report describes the geologic deposits revealed from the explorations and testing conducted for the Mackinac Straits Bridge and provides supplementary information from the Bruce DGR site in Ontario in similar rock conditions of the Michigan Basin.

The bedrock surface across the Straits indicates a deep trough near the middle, and may indicate that a healed fault zone or a deeply carved, ancient river channel may be present. The bedrock surface at this location may be less than 350 ft. below the average lake level. A simplified profile of the tunnel and these characteristics can be seen in Appendix E.

While the trough formation may run deeper than the tunnel alignment, a deeper profile may not be the best solution. The rock characteristics indicate occasional zones of permeable, fractured rock and karstic features that may require grouting during the shaft construction and tunneling process. Generally, groundwater infiltration requires pre-excavation grouting ahead of the TBM for approximately 8% of the tunnel length. An estimated 2,500 LF of grouting ahead of the TBM will be required along the alignment, and may be concentrated toward the middle of the tunnel drive at the trough area. This grouting will provide adequate support and prevent groundwater inflow in the case that a deeper trough is determined and permeability is encountered.

Additionally, to lower each shaft by 30 ft would cost an approximate $300,000 compared to the 2,500 LF of grouting which is estimated at $83,000 making the grouting a much more cost effective solution.

3.2.2.3 Tunnel Design

The proposed tunnel will be a straight, 3.75-mi. (6.01 km) long, segmental lined, 10- to 12-ft.-diameter tunnel excavated by TBM below the Straits. The final diameter will be selected based on cost considerations and TBM availability. The tunnel diameter is conceptually set at 10 ft. (3 m) based on considerations of the interior space required to be excavated and support the tunnel, and subsequently install the carrier pipe. More detail on the tunnel configuration is provided in Appendix E. The single purpose design includes sealing of the annulus between the tunnel periphery (inside the tunnel liner) and the pipe to maintain long-term tunnel stability, eliminate inflow, and minimize other threats to the pipeline.

Grout specifications would be selected on the basis of rock mass characteristics and final design details. The purpose of grouting would be to seal natural fractures in the rock mass (outside the tunnel liner), and to fill the annular space between the pipeline and the tunnel liner. This design would essentially create a low permeability buffer between the pipeline and the rock mass that would act as secondary containment for the pipeline, thus isolating the pipeline from the Great Lakes. The overall design would also prevent tunnel instability over the life of the pipeline, thus eliminating the possibility of direct impact of rock fall onto the pipeline. More detail on tunnel configuration is provided in Appendix E.

3.2.2.4 Cost Estimate

A conceptual level opinion of probable construction cost for the tunneling replacement alternative has been prepared. Conceptual costs consider the estimated duration, labor, materials, and equipment necessary to construct the launch and retrieval shafts, and the approximately 3.75-mi. (6 km) long tunnel.

Work productivity for construction of the launch and retrieval shafts is derived from previous experience and conservative assumptions for drilling and blasting advancement rates. Similar to the shafts, work productivity for tunneling, segmental liner installation, and carrier pipe placement is derived from experience on previous projects. Rates for materials, labor, and equipment necessary for construction of the tunnel alternative are derived from previously bid projects of similar size and scope, available industry data, and contractor quotes. In addition to the scope of conventional crossing installation, costs for the new pigging facilities, tie-ins to Line 5, and pipeline segments to the new crossing location are also included within this estimate.

Abandonment of the existing dual 20-in. pipelines crossing the Straits has been included in the estimate. The lines will be filled with water and abandoned in place. The abandonment costs are based on the Canadian National Energy Board (NEB) Abandonment Cost Estimates document MH-001-2012. Assumptions for the crossing abandonment can be found in detail in Appendix I.

The major cost categories and overall cost, in US dollars, are shown in the table below.

Table 3-2: Alternative 4b – Tunnel Cost Estimate

Cost Category	Alternative 4b Tunnel Crossing
New materials and transportation subtotal	$2,515,500
Construction, support services and abandonment subtotal	$145,221,000
Engineering and external consultants subtotal	$5,118,000
Total project cost	$152,854,500

3.3 Cost-Effectiveness and Market Impacts

3.3.1 Levelized Costs

Levelized cost methods and calculations are provided in Appendix P and summarized in Table 3-4. At the reference case discount rate (6%/y) the standalone levelized cost for these alternatives is $0.009/bbl to $0.046/bbl. This implies that if this activity were conducted on an independent system of 540,000 bbl/d, it would add the indicated amounts to the cost of that system.

Recall that the incremental levelized cost incorporates the total capital costs of each alternative: $27 million for trench crossing; $153 million for tunnel crossing. In either case there are no expected changes to operational costs of the Line 5 system.

Table 3-3: Levelized Cost and Market Impacts – Alternative 4

Alternative	Levelized Cost r=6%/y	Market Impact System Tariff	Market Impact Consumer
4A Trench Crossing	0.009 $/bbl	+0.0019 $/bbl	+0.005 ¢/gal
4B Tunnel Crossing	0.046 $/bbl	+0.0096 $/bbl	+0.027 ¢/gal

3.3.2 Market Impacts

As described in Appendix P the market impacts consider that costs incurred for Line 5 will be distributed in the market through an impact on all costs in the Lakehead System, forming part of the rate base of the system. The impacts of either of these alternatives are negligible. The highest impact (tunnel crossing) translates to $0.01/bbl when averaged over system throughput of 2600 bbl/d. If these costs were passed along to consumers of refined products within the broader market, it would translate to less than 0.03¢/gal. Distribution of this impact among producers, consumers, refiners or other users would not be discernible from other normal daily market forces that would potentially move prices. Notably, propane customers in the Upper Peninsula and crude producers in the Lower Peninsula would see no discernible impacts on propane prices or crude transportation tariffs.

3.4 Socioeconomic Impacts of Replacement Facilities

3.4.1 Introduction

Alternatives 4a and 4b entail the replacement of the Line 5 Straits Crossing. The trenched pipeline (Alternative 4a) requires pre-trenching the Straits, shoreline winch pulling the pipeline into place, and final burial of the pipeline. Tunnel construction requires the excavation of a 3.75-mi. (6.04 km) tunnel with a diameter of 10 ft. (3 m), plus two access shafts. Drill and blast activities will create launch and retrieval shafts; a tunnel boring machine (TBM) will create the tunnel. The pipeline placed within the tunnel will be encased in cement.

Replacement of the Line 5 Straits Crossing directly impacts the counties of Emmet, Cheboygan, and Mackinac. Trench construction will disrupt boat traffic in the Straits, as work crews trench and winch the pipeline into place. Adjacent shoreline areas will be temporarily transformed into worksites for materials delivery and machinery installation. Tunnel construction will involve minor water disturbance, but considerable disturbance on the shoreline at both ends of the tunnel. Tunnel excavation will require 4 to 7 acres (1.6 to 2.8 ha) for material storage and handling at each shaft. The material will need to be trucked elsewhere, increasing both traffic congestion and dust in all three counties. The estimated duration of the tunnel alternative is 27 months.

For both alternatives, there are economic impacts (jobs, income, output) associated with construction spending. As construction costs differ considerably between these two alternatives, their respective economic impacts are discussed separately in Section 3.4.2. Operating costs are discussed in Section 3.4.4. Other socioeconomic impacts are summarized in Section 3.4.4. All socioeconomic impacts associated with Alternative 4 are discussed in greater detail in Appendix Q.

3.4.2 Construction and Operations Economic Impacts

Economic multipliers (BEA RIMS II) were used to estimate the economic impacts of construction expenditures to replace the Line 5 pipeline crossing at the Straits. The construction cost to replace the existing pipeline with a trench pipeline is estimated at $27 million; to replace it with a tunnel pipeline, the cost is estimated at $153 million. Both of these estimates include construction costs of about $1 million associated with abandonment of the existing crossing.

3.4.2.1 Alternative 4a: Trench Pipeline Crossing Replacement

The results of the economic impact analysis for the trench pipeline replacement alternative (see Table 3-4) found that of the $27 million in construction expenditure, most will be spent on materials and services produced and provided by Michigan firms. For the State, this could generate about 145 direct (full- and part-time) jobs, and another 268 (full- and part-time) jobs from indirect spending on materials and services by supply contractors, and induced spending by employees linked directly or indirectly to the construction project. Total employment earnings would amount to some $21 million. Total output generated by the construction project would be about $71 million for a value added of $23 million.

Detailed results (see Appendix Q) show that Prosperity Regions 1, 2, 3, 5, and 6 could account for as many as 340 of the total 413 jobs, and for as much as $18 million of the total employment earnings.

Table 3-4: Alternative 4b – Tunnel Cost Estimate

Alternative 4a: Trench Pipeline for Line 5 Straits of Mackinac Crossing			
Construction Expenditures			$27 million
Michigan-sourced Construction Purchases			$22 million
Impact Area	Employment (jobs)	Labor Earnings (million $)	Output (million $)
Michigan			
Direct	145	7.9	27.3
Indirect	172	9.7	32.8
Induced	95	3.4	10.9
Total impact	413	21.0	71.0
Value Added for Michigan: $23 million			
Notes: Economic contribution results derived using BEA RIMS II Multipliers.			

The contribution of this alternative to government revenue is estimated to be $1.0 million through consumer income taxes, sales taxes, and transportation fuel taxes. This estimate is for Michigan as a whole, and is not attributed to counties or Prosperity Regions within the state. The reader is reminded that impacts and revenues from a short-term activity will not necessarily occur in the period of the original investment.

3.4.2.2 Alternative 4b: Tunnel Pipeline Crossing Replacement

The results of the economic impact analysis for the tunnel pipeline replacement alternative (see Table 3-5) found that of the $153 million in construction expenditure, over half – about $92 million – would be spent on materials and services produced and provided by Michigan firms. Within the state, this would generate about 810 direct (full- and part-time) jobs and another 950 (full- and part-time) jobs from indirect spending on materials and services by supply contractors, and induced spending by employees linked directly or indirectly to the construction project. Total employment earnings would amount to some $91 million. Total output generated by the construction project would be about $329 million for a value added of $93 million.

Detailed results (see Appendix Q) show that the Prosperity Regions 1, 2 3, 5, and 6 could account for as many as 1,500 of the total 1,760 jobs, and for as much as $79 million of the employment earnings of the total employment earnings.

Table 3-5: Alternative 4b: Tunnel Pipeline Crossing Construction

Alternative 4b: Tunnel Pipeline for Line 5 Straits of Mackinac Crossing	
Construction expenditures	$153 million
Michigan-sourced construction purchases	$92 million

Alternative 4b: Tunnel Pipeline for Line 5 Straits of Mackinac Crossing			
Impact Area	Employment (Jobs)	Labor Earnings (million $)	Output (million $)
Michigan			
Direct	814	44	152.9
Indirect	635	36	139.8
Induced	314	11	35.8
Total impact	1,763	91	328.5
Value Added for Michigan: $93 million			
Note: Economic contribution results derived using BEA RIMS II Multipliers.			

The contribution of this alternative to government revenue is estimated to be $4.4 million through consumer income taxes, sales taxes, and transportation fuel taxes. This estimate is for Michigan as a whole, and is not attributed to counties or Prosperity Regions within the state. The reader is reminded that impacts and revenues from a short-term activity will not necessarily occur in the period of the original investment.

3.4.3 Alternative 4: Crossing Replacement Operation Costs

Operation costs of Line 5 with a replaced pipeline segment – a trench pipeline or a tunnel pipeline – to cross the Straits are expected to remain essentially unchanged from their current level. Therefore the economic contribution of the operation expenses of Line 5 in Michigan will remain as they are now. (The economic contribution of the status quo is estimated in Section 2.3.1 and Appendix Q.3.1).

3.4.4 Social Impact Screening

For each alternative, Appendix Q provides socioeconomic analysis for SIA screening; the results of which are summarized in Table Q-6 (see Appendix Q). Under Alternative 4, for both crossing replacement alternatives, the SIA screening draws attention to potentially significant population impacts (particularly housing), and community structural impacts (related to the tourism sector). With respect to the tunnel alternative, potential air pollution and noise impacts are flagged. With respect to the trench alternative, potential water traffic impacts are flagged.

In the case of Alternative 4, construction operations are stationed in the counties adjacent to the Straits: Mackinac, Emmet, and Cheboygan. These three counties are particularly sensitive to community resource impacts because their economies are dependent on seasonal tourism. They all experience large influxes of tourists and seasonal workers, which under normal conditions stress community resources. The area has a large rental housing market, which reflects anticipated seasonal demand from tourists and seasonal workers. However, to the extent that construction crews constrain rental housing supply during the tourism months, the tourism sector (businesses, tourists, seasonal workers), and community resources (policing, medical) could be stretched beyond their limits and negatively impacted.

Construction to replace the Straits Crossing pipeline would be stationed in an urban area, and machinery and equipment operation would affect local road and highway infrastructure in a relatively densely populated area. Tunneling operations in particular require the extraction and trucking of large amounts of rock and soil; dust and noise will impact community residents and visitors.

Regarding the trench pipeline replacement, the nature of its construction will require disruption of water traffic through the Straits. The Straits is an important link between Lake Michigan and Lake Huron. Important to recreational boating and fishing, it is a fundamental part of the tourism attraction to the region. It is also part of the area's tribal treaty waters, and important for tribal commercial and subsistence fisheries. The impacts of any disruption to water traffic needs careful assessment with area tribes, the MDNR Fisheries Division, and others affected by lake traffic in the area.

The screening conducted in this report is a preliminary assessment and has not included any public processes to define concerns and develop potential mitigation measures. Mitigation measures for concerns are usually developed closer to more detailed stages of project development.

3.5 Risk Assessment of Pipeline Failure – Conventional Replacement

3.5.1 Failure Probability Analysis

The probability of failure is related to the threats (potential causes of loss of containment) that apply to a given segment. The threats that apply along that segment relate to its design, materials operating conditions and surrounding environment. The failure probability analysis was undertaken by first characterizing the vulnerability of each potential threat, based on an evaluation of threat attributes (*Threat Assessment*). The *Threat Assessment* provides a basis for characterizing each threat as a 'Principal Threat' or a 'Secondary Threat'. Principal Threats are defined as those threats for which an evaluation of susceptibility attributes indicates a significant vulnerability, and that have the potential to provide the most significant contributions to overall failure probability. Secondary Threats are defined as those threats for which an evaluation of susceptibility attributes indicates a relatively insignificant or non-significant vulnerability and that therefore have the potential to contribute only at a second-order or potentially negligible levels in terms of overall failure probability.

By reviewing all relevant data attributes that influence each threat, the *Threat Assessment* also serves as the basis of developing a strategy for making quantitative estimates of failure probability. These quantitative estimates of failure probability are then made for all threats that have the potential to contribute to overall failure likelihood at non-negligible levels.

3.5.1.1 Methodology

Quantitative estimates of failure probability were based on a two-step analysis. The first step involved a *Threat Assessment* (described in Section 3.5.1.1.1) in which the vulnerability to each of a number of potential threats were determined. As part of the *Threat Assessment*, approaches for quantifying threat-specific failure probability were selected, giving consideration to threat attribute data, as well as best practice methodologies. Using these approaches, threat-specific quantitative estimates of failure probability were then generated in the second step of the analysis – the Probability Analysis (described in Section 3.5.1.1.2).

3.5.1.1.1 Threat Assessment

The primary objective of the *Threat Assessment* was to review the attributes for all potential threats to the hypothetical 30 in. diameter Straits Crossing pipeline segment constructed using conventional trenched installation methods. Through this review, the relevance and severity of each threat was assessed in in consideration of the design, materials, installation and operating conditions associated with the replacement segment.

As a variety of failure likelihood estimation approaches exist, with each requiring specific data sets, the *Threat Assessment* also considered the availability and type of data for each threat to assist in the selection of the optimal approach of determining the failure probability each relevant threat.

The *Threat Assessment* has been structured as follows:

- Section 3.5.1.1.1.1 - Scope: Description of the pipeline segments and operating conditions
- Section 3.5.1.1.1.2 - *Threat Assessment* Approach: Identification of the threats considered and a description of the approach
- Section 3.5.1.1.1.3 – Assessment of Threats: Review of all threat attributes and an assessment of threat potential
- Section 3.5.1.1.1.4 – Threat Potential Summary: Summary of the threat potential for each threat, as well as description of the candidate approaches for estimating failure probability based on the availability, quality, and completeness of the data attributes for each threat

3.5.1.1.1.1 Scope

The *Threat Assessment* was conducted for the single 30 in. diameter Straits crossing pipeline using conventional trenched installation methods. The design details of these pipeline segments are summarized in Table 3-6.

Table 3-6: Design Details – 30-in. Straits Crossing Segment – Conventional Installation

Design Variable	Value
Pipe material	Longitudinally double submerged arc-welded (L-DSAW), CS line pipe manufactured to API 5L
Diameter	30 in.
Wall thickness	0.812" (0.224" required for containment, 0.588" corrosion / mechanical allowance)
Grade	X65
Pressure test	1.25 x design pressure – 875 psi min. (6,033 kPa min.)
Pump station locations	Per existing locations
Maximum operating pressure	600 psi (4,137 kPa)

Design Variable	Value
Design pressure	750 psi (5,171 kPa)
ILI frequency (assumed)	Per existing practice (high-resolution axial MFL and geometry inspections conducted every five years)
Installation type	Trenched –3.28 ft. (1.0 m) cover

3.5.1.1.1.2 Threat Assessment Approach

The *Threat Assessment* followed the same approach as described in Section 2.4.1.1.1.2, using API 1160 Annex A as a guide document, augmented with a review of threat attributes outlined in ASME B31.8S Appendix A. The *Threat Assessment* proceeded on a threat-by-threat basis, to establish the vulnerability of the 30 in. conventional pipeline replacement to each threat.

In pipeline risk assessment, it is often found that certain threats dominate the overall threat environment, with other threats contributing to overall failure probability at levels that are orders of magnitude below, and within estimation error of the most dominant threats. With this in mind, and as the goal of the *Threat Assessment* was to support a quantitative estimation of failure probability, threats were categorized as:

1. Principal Threats (those threats for which an evaluation of susceptibility attributes indicates a significant vulnerability, and that have the potential to provide the most significant contributions to overall failure probability), and,
2. Secondary Threats (those threats for which an evaluation of susceptibility attributes indicates a relatively insignificant or non-significant vulnerability and that therefore have the potential to contribute only at a second-order or potentially negligible levels in terms of overall failure probability)

3.5.1.1.1.3 Assessment of Threats

API 1160 – Managing System Integrity for Hazardous Liquid Pipelines lists 12 potential threats that should be assessed for the operation of hazardous liquids pipelines as follows:

1. External corrosion
2. Internal corrosion
3. Selective seam corrosion
4. Stress Corrosion Cracking (SCC)
5. Manufacturing defects
6. Construction and fabrication defects
7. Equipment failure (non-pipe pressure containing equipment)
8. Immediate failure due to mechanical damage
9. Time-dependent failure due to resident mechanical damage
10. Incorrect Operations
11. Weather and outside force
12. Activation of resident damage from pressure-cycle-induced fatigue

As noted in API 1160, not each of the above 12 threats may necessarily apply to the pipe segment being considered in the risk evaluation, and so guidance is provided in Annex A of that document with respect to how the attributes of each threat may be evaluated to assess vulnerability. As the scope of the risk assessment being performed under Alternative 4 – Conventional Replacement is limited to a single 30-in. diameter pipeline installed using conventional trenched installation across the Straits, the evaluation of threat attributes for each of the above potential threats was conducted as they relate to that replacement pipeline.

Using the threat attribute guidance provided in API 1160 Annex A, augmented with a review of threat attributes outlined in ASME B31.8S Appendix A, an evaluation of each threat attribute associated with the threats listed above is provided below.

3.5.1.1.1.3.1 External Corrosion

A summary of the threat attribute review and assessment for the threat of external corrosion as it relates to the Straits crossing pipelines is provided below.

3.5.1.1.1.3.1.1 Coating Type

It has been assumed that three-layer polyethylene (3LPE) will be used as a corrosion coating for the replacement pipeline. 3LPE is a type of high performance composite coating which consists of a fusion bonded epoxy (FBE) layer, a bonding layer, and an outer layer of polyethylene. A high-performance coating system that is compatible with the 3LPE coating will be selected as the joint coating.

High-performance coating systems are resistant to a wide range of chemicals, and are also resistant to impact damage, disbondment, and time-related degradation processes.

3.5.1.1.1.3.1.2 Cathodic Protection

Cathodic protection (CP) is an electrochemical method used to prevent or control corrosion of buried or submerged metallic structures such as pipelines. CP systems are active systems which rely on the application of electric current to control corrosion by making the structure to be protected the cathode in an electrochemical cell.

It is assumed that the existing remote rectifiers currently located both north and south of the Straits crossing will be used to provide cathodic protection of the replaced pipeline, although it is likely that some rebalancing of current outputs will be required to address changes in current demand following pipe replacement.

3.5.1.1.1.3.1.3 Corrosion Assessment and Monitoring

It is assumed that a baseline in-line inspection will be performed soon after installation, using a high-resolution magnetic flux leakage (MFL) tool. Thereafter, it is assumed that the current practice of conducting in-line inspections of the Straits Crossing every five years will continue. The baseline survey will confirm that there are no structurally significant wall loss defects present, and will serve as a basis for comparison for all future in-line inspections, enabling pit-matching and feature growth analysis to be conducted. This will enable monitoring of sub-critical wall loss and the completion of appropriate interventions or repairs before flaws grow to a critical size.

3.5.1.1.1.3.2 Internal Corrosion

Internal corrosion susceptibility is primarily influenced by product stream characteristics - both product stream composition and flow characteristics. Where, based on an evaluation of these product stream characteristics, it is considered that there is potential for internal corrosion, monitoring coupons or probes, placed at locations of potential water accumulation can provide near-real-time monitoring of ongoing internal corrosion and corrosion growth rates.

3.5.1.1.1.3.2.1 Product Stream Characteristics

The extensive (64 year) operating experience associated with the transportation of the products carried by Line 5 through the Straits has shown that these products have not caused internal corrosion to occur through the Straits Segment (See Section 2.4.1.1.1.3.2). This is attributed to product composition as well as flow characteristics. With respect to the latter, flow modeling has demonstrated that the existing Straits crossing segments operate in a fully-turbulent mode, thereby entraining the limited amounts of water and solids within the product stream, and maintaining the pipe inside surface in an oil-wet (non-corrosive) condition.

For the hypothetical NPS 30 pipeline Straits Crossing replacement pipeline, an analysis was conducted to determine the flow conditions (turbulent vs. laminar flow) similar to the analysis conducted for the existing Straits pipelines (Section 2.4.1.1.1.3.2).

The calculation for the NPS 30 Straits Crossing segment was based on the following parameters:

Table 3-7: Design Parameters Assumed for 30-in. Straits Replacement Segment (Trenched)

Variable	Units	Value	Notes
Pipe diameter	in.	30	30-in. pipe
Wall thickness	in.	0.812	Conventional crossing specific
Hydraulic diameter (DH)	in.	28.38	Pipe ID
Flow area (A)	ft^2 (m^2)	4.39 (0.408)	
Flow rate	bbl/d	540,000	
Flow rate (Q)	ft^3/s (m^3/s)	126,328 (3,577)	
Kinematic viscosity (v)	Highest batch product kinematic viscosity at 50°F (10°C) based on the information provided by Enbridge.		

Note that the highest viscosity of the batched fluids was used to determine the lowest Reynolds, which is a conservative assumption.

Using these parameters yields the Re result of approximately 115,000. Flow in a pipeline can be considered fully turbulent at Reynolds numbers greater than 4,000. Reynolds numbers in the range of 2,000-4,000 indicate transitional flow from laminar to turbulent, and numbers less than 2,000 are fully laminar.

Consequently, the flow through the hypothetical 30 in. Straits Crossing replacement segment falls fully within the turbulent range, which is the same flow regime currently experienced within the existing 20-in. Straits Crossing segments. This suggests that the current internal corrosion-free performance of the Straits crossing segments will continue should it be replaced with a single 30 in. diameter pipeline.

3.5.1.1.1.3.2.2 Corrosion Assessment and Monitoring

Given the operating experience, it is assumed that corrosion coupons or probes to provide near-real-time monitoring of internal corrosion and growth rates would not be required in the 30 in. Straits Crossing segment, however they could be deployed at a later date, if warranted. It is assumed, however, that a baseline in-line inspection will be performed soon after installation, using a high-resolution magnetic flux leakage (MFL) tool. Thereafter, it is assumed that the current practice of conducting in-line inspections of the Straits Crossing every five years will continue. The baseline survey will confirm that there are no structurally significant wall loss defects present, and will serve as a basis for comparison for all future in-line inspections, enabling pit-matching and feature growth analysis to be conducted. This will enable monitoring of sub-critical wall loss and the completion of appropriate interventions or repairs before flaws grow to a critical size.

3.5.1.1.1.3.3 Selective Seam Corrosion

Selective seam corrosion is a form of preferential corrosive attack that has been documented to occur along the seam of some types of pipe, limited to low-frequency electric resistance welded (LF-ERW), direct-current electric resistance welded (DC-ERW), flash welded (FW) and susceptible high-frequency electric resistance welded (HF-ERW) pipe. [35, p. 40] This threat is not associated with modern double submerged arc welded pipe coated with a high-performance coating system, such as is assumed for the 30 in. Straits replacement segment.

3.5.1.1.1.3.4 Stress Corrosion Cracking

Stress Corrosion Cracking (SCC) is a form of environmentally assisted cracking, wherein small surface cracks can form and grow over time. Other forms of environmental cracking, such as sulfide stress cracking (SSC), occur only in sour (H_2S-bearing) environments. H_2S in liquid is a quality parameter that is measured and monitored on Enbridge transport commodities. This monitoring ensures that Line 5 does not transport sour products [56], and is therefore not vulnerable to sour service cracking mechanisms.

In SCC, multiple small individual cracks will typically form adjacent to one another in an array. If the cracks continue to grow, they frequently overlap and/or coalesce such that they become the equivalent of a large single crack in terms of their effect on the pressure carrying capacity of the pipe. Eventually such overlapping and coalescence can create a crack large enough to cause the pipeline to leak or rupture.

It is generally agreed that fusion-bonded epoxy (FBE) (which is incorporated into the 3LPE coating system assumed for the 30 in. Straits Replacement segment) is an effective protection against SCC [131, p. 29], and to date, there have been no known failures attributed to SCC associated with FBE-based coatings. Although this one factor is sufficient to address the threat of SCC, it should be noted that the operating stress level that is assumed for the 30 in. Straits Replacement segment (17% of the specified yield strength of the pipe material at maximum operating pressure) is very low relative to the 60% lower-bound level that is normally associated with SCC. [131, p. 84]

3.5.1.1.1.3.5 Manufacturing Defects

API 1160 attributes pipeline failures associated with the threat of Manufacturing Defects to pipe seam defects, and pipe body defects, including hard spots, cracks, laminations, pits, scabs, and slivers. Of the above, seam defects, hard spots, cracks, and laminations have been direct causes of pipeline failure, whereas pits, scabs and slivers are surface imperfections that can adversely affect coating integrity.

Manufacturing defects that are not found by means of the pipe manufacturer's hydrostatic test and/or non-destructive examinations and are not eliminated by the initial preservice hydrostatic test of the pipeline, will remain as anomalies in the pipeline. Frequently, such anomalies are revealed by inline inspection or hydrostatic retests. Having survived an initial preservice hydrostatic test to a level of at least 1.25 times MOP, these types of anomalies will be non-injurious to pipeline integrity unless they are subject to enlargement by pressure-cycle induced fatigue.

Vulnerability factors associated with failures caused by manufacturing defects include: [62, p. 93]

- The presence of pressure-cycle induced fatigue,
- Operation at operating stress levels in excess of 30% of specified minimum yield strength, and
- The absence of a pre-commissioning hydrostatic test to a pressure of at least 125% of maximum operating pressure.

The relevance of the above susceptibility factors in respect of a hypothetical replacement of the Straits crossing with 30 in. double submerged arc welded pipe are summarized as follows:

3.5.1.1.1.3.5.1 Pressure-Cycle Induced Fatigue / Operating Stress Level

As discussed in Section 2.4.1.1.1.3.5, an assessment of the operating pressure spectra associated with the existing 20-in. Straits Crossing segments resulted in the lowest-possible pressure-cycle fatigue rating ('Light'). This pressure cycle regime is not associated with industry experience of pressure-cycle-induced fatigue failures of pre-existing sub-critical flaws. In a fatigue calculation, the upper-bound stress range is limited by the operating stress at maximum operating pressure. In the case of the existing 20-in. Straits Crossing segments, this maximum operating stress level is 21% of the minimum specified yield strength of the pipe material, which is considered quite low, relative to typical onshore transmission pipelines. For the design considered in the 30 in. Straits replacement pipe segment, the maximum operating stress level is even lower, at 17% of minimum specified yield strength. Accordingly, pressure-cycle induced fatigue is not considered to be a concern for this pipe segment.

3.5.1.1.1.3.5.2 Hydrostatic Testing

A hydrostatic test to 1.25 x design pressure is assumed for this installation. This translates to 875 psi, or 1.46 x maximum operating pressure. In the absence of significant pressure cycle-induced fatigue, hydrostatic testing to minimum 1.25 x maximum operating pressure provides assurance that manufacturing defects will not grow to failure in service. [132, p. 1]

3.5.1.1.1.3.5.3 Line Pipe Quality Considerations

The hypothetical 30 in. Straits Crossing segment will be constructed of modern, double submerged arc welded line pipe, which, by law, must conform to the requirements of API 5L. The manufacturer's quality management system will therefore have undergone verification with the demonstrated ability to meet specific product specification requirements. Nevertheless, it is worthy of note that even in pipelines that are constructed of vintage materials that have been associated long seam defects, only one of the following two conditions are adequate to characterize the pipeline as 'Not Susceptible to Seam Failures': [133]

1. Operation at or below 30% of specified minimum yield strength of the line pipe material; or,
2. Hydrostatic test to at least 1.25 x maximum operating pressure and pressure cycles characterized as 'Light' or 'Moderate'

As the 30 in. Straits Crossing replacement will meet both of those conditions, it should be concluded that it will be characterized as Not Susceptible to Seam Failures. Nevertheless, as part of developing installation costs associated with this Alternative, it has been assumed that a baseline inspection will be completed using an in-line inspection tool that is capable of detecting seam defects.

3.5.1.1.1.3.6 Construction and Fabrication Defects

API 1160 attributes pipeline failures associated with the threat of Construction Defects to installation damage, such as rock dents, and bending marks, buckles and wrinkles, as well as girth weld and fabrication weld defects.

3.5.1.1.1.3.6.1 Installation Damage

Damage caused during installation, such as dents, buckles and wrinkles is readily detectable by in-line inspection tools that are specially configured to detect mechanical damage. As part of developing installation costs associated with this Alternative, it has been assumed that a baseline inspection will be completed using an in-line inspection tool that is capable of detecting these types of defects.

3.5.1.1.1.3.6.2 Defects in Girth Welds and Fabricated Fittings / Branch Connections

Modern pipeline construction practice involves the imposition of quality control measures, such as the adherence to qualified welding procedures, the qualification of welders, and the use of non-destructive inspection techniques for weld examination helps to prevent the occurrence of large, structurally-significant girth weld defects. Pipeline failures resulting from defects in modern girth welds as the primary cause of failure are rare. [35, p. 76] Because girth weld defects lie in the plane of principal operating stresses, some form of extreme external loading is generally required for them to play a role in pipeline failure. This form of external loading is addressed in Section 3.5.1.1.1.3.11 - Weather and Outside Force.

3.5.1.1.1.3.7 Equipment Failure

API 1160 characterizes Equipment Failure as the failure of non-pipe pressure-retaining equipment, such as pumps, valves, seals, O-rings, meters, pressure switches, temperature gauges, prover loops, scraper traps, strainers, truck loading racks, etc. This type of equipment is normally associated with the types of equipment found mostly at terminals and pump stations, and none of this type of equipment is part of the design of the Straits Crossing segment assumed for the 30 in. Straits Crossing replacement.

3.5.1.1.1.3.8 Immediate Failure Due to Mechanical Damage

In onshore pipeline experience, immediate failure due to mechanical damage is typically associated with excavation, drilling, boring, farming, or other soil moving or removal activities where the mechanical equipment being used comes in contact with a buried pipeline causing it to leak or rupture, as well as (much more infrequently), acts of sabotage or vandalism. In offshore pipelines, the greatest threat associated with mechanical damage is shipping activity, such as dropped objects (principally a concern only in the vicinity of production platforms), trawl board damage (confined to ocean environments where bottom trawling is used), or inadvertent anchor deployment and dragging. This last mechanical damage category, which involves the threat of pipelines being hooked by anchors that are unintentionally dropped while ships are underway, and subsequently dragged, has seen a heightened focus on the part of pipeline owners and operators, due to an increase in frequency. [71, p. 23] Of these, it is the anchor-hooking scenario that poses the greatest risk to a pipeline that crosses a busy shipping lane such as the Straits. This scenario is described in greater detail in Sections 2.4.1.1.1.3.8 and 2.4.1.1.2.1.1 with respect to the existing 20-in. diameter Straits crossing segments. Those segments are installed on top of lake bottom, and are therefore more vulnerable to anchor-hooking than a pipeline that is buried at a depth of cover of 3.3 ft. (1 m).

In order to ensure that the 3.3 ft. (1 m) burial depth is maintained, certain measures have been considered as part of the capital and operating costs associated with the trenched installation of the 30 in. diameter Straits Crossing. As a first measure, an Inertial Mapping Unit (IMU) in-line inspection will be required immediately post-installation. This will provide (x,y,z) positional data through the length of the crossing, which, when coupled with a multi-beam echo sounder (MBES) bathymetric survey (also required), will provide assurance that the specified minimum depth of cover has been achieved. Thereafter, annual MBES surveys for the first 5 years of operation (every 2 years thereafter), along with any necessary remedial action will be required to ensure that the specified minimum depth of cover is maintained.

Regardless of whether the minimum specified depth of cover is maintained through the Straits, and insofar as anchors of large shipping vessels have the potential to penetrate to depths greater than the 1.0 m (3.3 ft) burial depth, the potential for anchor hooking will not be completely eliminated by maintaining cover. Therefore, anchor-hooking must be considered as a potential threat.

3.5.1.1.1.3.9 Time-Dependent Failure Due to Resident Mechanical Damage

Dents and gouges caused by installation damage (Section 3.5.1.1.1.3.6) or external interference (Section 3.5.1.1.1.3.8) that do not result in immediate failure, may, if they go undiscovered, become more severe with the passage of time such that eventually they cause a leak or a rupture. In order for pre-existing sub-critical damage to become more severe with the passage of time, a growth mechanism is required. Potential growth mechanisms are corrosion, environmental cracking, ductile tearing due to external forces or pipe movement, or pressure-cycle-induced fatigue. [35, p. 77]

Mechanical damage is readily detected with in-line inspection metal loss tools and geometry tools, especially if used in combination, and this is the best means to locate and mitigate any such anomalies. As part of developing installation and operating costs associated with this Alternative, it has been assumed that a baseline inspection will be completed using an in-line inspection tool that is capable of detecting mechanical damage. This will be effective in identifying any potentially injurious mechanical damage that has been caused during installation. Thereafter, it has been assumed that in-line inspections, capable of identifying mechanical damage will be completed every 5 years, and that MBES surveys, which are capable of identifying evidence of past anchor drag events will be completed at 1-2 year intervals.

Regardless, anchor drag scenarios all involve dragging an anchor through the Straits where there is heightened concern and awareness of submarine infrastructure, such as buried communication/electrical cables, and pipelines. Consequently, it is almost impossible to foresee a circumstance whereby a serious incident of this nature could go both un-detected and un-reported.

3.5.1.1.1.3.10 Incorrect Operations

API 1160 characterizes failures attributed to Incorrect Operations as including, but not necessarily limited to “accidental overpressurization; failure to design properly for or limit surges; improper closing or opening of valves; overfilling tanks; exercising inadequate or improper corrosion control measures; and improperly maintaining, repairing, or calibrating piping, fittings, or equipment”.

There have been two overpressurization events at the North Straits station in the past 5 years. In both cases, MOP overpressures were case overpressures within North Straits station, and the affected piping was not within the span of Line 5 that is underwater. [74]

While Enbridge has undertaken numerous initiatives to improve the management systems, procedures and practices by which it controls its operations since the 2010 Marshall Incident, it is often impossible to foresee in advance what sequence of events and breakdown in management systems and operating practices might lead to failure. While, under this Alternative, the 30 in. pipeline is assumed to be buried with a minimum of 1 m (3.3 ft) of cover, a review of industry incident data shows that this is not sufficient to prevent ongoing maintenance operations from accidentally interfering with a pipeline and causing a failure. Therefore, the potential for failures that are related to the threat of Incorrect Operations cannot be discounted.

3.5.1.1.1.3.11 Weather and Outside Force

The threat of weather and outside force pertains to discrete, localized hazards associated with potential weather-related events (such as floods or lightning strike), geohazards (such as slope failure or rock fall), seismic hazards (including lateral spreading due to soil liquefaction), and hydrotechnical forces (such as scour, or vortex-induced vibration) that may, or may not be present at discrete, specific locations along a pipeline segment. Where attributes associated with any of the above threats are present at a given location, the associated pipeline segment is considered to be vulnerable to failure due to that threat mechanism; otherwise, absent vulnerability factors, the pipeline is not considered to be vulnerable. As detailed in the *Geotechnical Report* (see Attachment 3 in Appendix S), the only significant geotechnical or Hydrotechnical threats to pipeline integrity that are found within the Straits are those related to spanning. With the measures described in Section 3.5.1.1.1.3.8 taken to manage loss of cover and prevent spanning, geotechnical and Hydrotechnical threats will be managed to negligible levels.

3.5.1.1.1.3.12 Activation of Resident Damage from Pressure-Cycle Induced Fatigue

Resident sub-critical damage may become activated, and may grow to a critical size under the influence of pressure-cycle induced fatigue. Repeated cycles of stress are known to cause defects above a certain threshold size to grow, and if the growth continues long enough the defect can cause structural failure. The severity of this threat is strongly dependent on the initial size of the defect, and the severity of the pressure cycles in terms of stress range and frequency.

Pressure-cycle-induced fatigue might play in growing sub-critical defects associated with other threats to failure. Sub-critical defects that do not experience growth in service are considered to be stable defects that have a factor of safety established through post-installation hydrostatic testing.

The degree to which fatigue can contribute to the growth of sub-critical defects is a function of the magnitude and frequency of individual pressure cycles that exist within the operating pressure spectrum of a pipeline. Pressure-cycle induced fatigue is discussed in detail in Section 2.4.1.1.1.3.12. That discussion describes an analysis of the pressure spectra associated with the operating conditions of the Straits Crossing pipeline. That analysis was completed to assess the pressure-cycling severity on that pipeline segment, and the potential for operating pressure cycling to contribute to the growth of sub-critical defects by means of fatigue mechanisms. That analysis found that the pressure profile for the Straits Crossing segments is classified as “Light”, meaning that the operating pressure spectrum that is characteristic of the Straits Crossing is not associated with pipelines that would experience failures due to activation of sub-critical defects by pressure-induced fatigue.

As discussed in Section 3.5.1.1.1.3.5, pressure-cycle induced fatigue is not considered to be a concern for this pipe segment.

3.5.1.1.1.4 Threat Potential Summary

As outlined in Section 3.5.1.1.1.2, one of the goals of the *Threat Assessment* is to classify each threat into one of two categories:

- Principal Threats (those threats for which an evaluation of susceptibility attributes indicates a significant vulnerability, and that have the potential to provide the most significant contributions to overall failure probability), and,
- Secondary Threats (those threats for which an evaluation of susceptibility attributes indicates a relatively insignificant or non-significant vulnerability and that therefore have the potential to contribute only at a second-order or potentially negligible levels in terms of overall failure probability),

Based on the preceding analysis of threat attributes, Immediate Failure due to Mechanical Damage and Incorrect Operations are characterized as Principal Threats. Given the design, materials and operating characteristics of the hypothetical 30 in. diameter Straits crossing segment, those two threats have the potential to contribute to overall failure probability to the greatest extent. While it is acknowledged that the combined contribution to overall failure probability of the remaining threats is not zero, an evaluation of their threat attributes suggests that their contribution would not be significant relative to the Principal Threats. Therefore, failure probability estimates will be provided only for the two Principal Threats.

3.5.1.1.2 Probability Analysis

The failure probability analysis for the hypothetical replacement of the Straits Crossing with a 30 in. diameter pipeline for the two Principal Threats of Immediate Failure due to Mechanical Damage and Incorrect Operations is provided in this Section.

3.5.1.1.2.1 Immediate Failure due to Mechanical Damage.

In offshore pipelines, the greatest threat associated with mechanical damage is shipping activity, and for the hypothetical 30 in. diameter trenched Straits replacement, the most significant shipping-related threat is the potential inadvertent anchor deployment and dragging while ships are underway. A description of the scenario development associated with this threat is provided in Section 2.4.1.1.1.3.8.

3.5.1.1.2.1.1.1 Approach

The standardized approach described in Section 2.4.1.1.2.1.1, based on Appendix E of Reference [71], was followed to estimate the annual probability of failure due to interaction with an anchor that is inadvertently deployed from a ship underway. As outlined in that Section, three potential outcomes are considered with respect to this threat:

Outcome 1: Drop discovered within 1 km, and actions are taken. Anchor does not get seated, and reaches a maximum penetration depth corresponding to the perpendicular offset distance between the fluke and shank (75% of all accidental deployment occurrences; 2.0×10^{-08} per ship crossing);

Outcome 2: Anchor seats within 1 km and attains maximum penetration depth (6.25% of all accidental deployment occurrences; 1.7×10^{-09} per ship crossing)

Outcome 3: Anchor does not get seated, and is dragged for a greater distance, with maximum penetration depth corresponding to the perpendicular offset distance between the fluke and the shank (18.75% of all accidental deployment occurrences; 1.7×10^{-07} per ship crossing)

3.5.1.1.2.1.1.2 Analysis

Vessel Transit Frequency Distribution

Using NAIS data, a vessel transit frequency distribution was generated as described in Section 2.4.1.1.2.1.1 so that the average number of transits through the Straits of ships displacing more than a critical value could be determined.

Feasibility of Anchor Interaction

For a vessel having a given displacement, in order for anchor interaction with a pipeline to occur, two conditions must exist:

1. The water depth must be no deeper than the anchor chain length; and,
2. The projected fluke length of the anchor must be at least as great as one-half the pipe diameter.

Tabulated values of anchor chain length and anchor projected fluke length by vessel class are provided in Tables E.1 and E.2 of DNV Report No. 2009-1115, and this information is summarized below.

Table 3-8: Anchor and Chain Dimensions by Vessel Class (DNV Report No. 2009-1115)

Vessel Class	Displacement (tonnes)	GRT from	GRT to	Anchor Chain Length (m)	Anchor Mass (kg)	Anchor Projected Fluke Length (m)
I	1500	100	499	179	900	0.6
II	3600	500	1599	207	1440	0.6
III	10000	1600	9999	248	3060	0.9
IV	45000	10000	59999	317	8700	1.3
V	175000	60000	99999	372	17800	1.6
VI	350000	100000	-	385	26000	1.9

At the location of the existing Straits Crossing, the deepest water depth is 249 ft. (76 m). Also, the half-pipe-diameter dimension of the hypothetical 30-in. diameter replacement of the Straits Crossing with 2-in.” concrete coating is 17 in. (0.432 m). Based on these values, it can be seen that the anchor chain lengths for anchors in all vessel classes are such that they will enable hooking of a pipeline at the bottom of the Straits. Furthermore, the perpendicular offset distance of anchors in all classes is greater than half the pipe diameter of the pipeline plus coating, and so hooking can occur for anchors from vessels in all classes, provided that the anchor comes into full contact with the pipeline.

For Outcome 2, which involves a seated anchor, the penetration depth (and hence, the potential to hook the pipeline) is a function of soil type and ship class, as outlined in Table 3-9 (reproduced from Table E.3 of DNV Report No. 2009-1115).

Table 3-9: Anchor Penetration Depth (Outcome 2 – DNV Report No. 2009-1115)

Vessel Class	Displacement (tonnes)	Soil Type	Anchor Penetration Depth m (ft)
I	1500	Hard Soil	0.60 (1.97)
II	3600		0.65 (2.13)
III	10000		0.89 (2.92)
IV	45000		1.30 (4.27)
V	175000		1.64 (5.38)
VI	350000		1.87 (6.14)
I	1500	Soft Soil	1.79 (5.87)
II	3600		1.94 (6.36)
III	10000		2.68 (8.79)

Vessel Class	Displacement (tonnes)	Soil Type	Anchor Penetration Depth m (ft)
IV	45000		3.89 (12.76)
V	175000		4.91 (16.11)
VI	350000		5.62 (18.44)

As the condition of the lakebed has been described as varying between sandy and clay, the soft soil conditions of the above table apply. Therefore, for Outcome 2, with the hypothetical 30 in. Straits Crossing pipeline buried at a depth of 1.0 m (39"), anchors from all vessel classes have the potential to hook the pipeline.

Outcomes 1 and 3 are associated with a scenario in which the dragged anchor does not get seated, and penetration is therefore limited to the perpendicular offset distance of the flukes. For those Outcomes, in order for anchor hooking to occur, the perpendicular offset distance of the anchor flukes must be at least equal to the dimension [(pipe burial depth) + (1/2 the coated-pipe diameter)]. With the hypothetical 30 in. diameter Straits crossing pipeline buried at a minimum depth of 1.0 m (39.4"), this means that only those anchors that have perpendicular offset distances of 1.43 m (56.4") can hook the pipe in Outcomes 1 and 3. By curve-fitting the data contained in Table 3-8, ships displacing more than 93,960 tonnes have anchors with perpendicular offset distances greater than this value, and therefore, only those ships have the potential to hook a 30 in. pipeline with 2 in. concrete coating buried at a minimum depth of 1.0 m (39.4").

Critical Force Analysis

DNV Report No. 2009-1115 provides tabulated critical force limits for strain (based on finite element analysis) and dent (based on limit state models) for a range of pipe diameters in both hard and soft soils, and in a variety of installed conditions, including trenched, with a 1.0 m depth of cover. The smaller of the two forces (force required to cause critical strain and force required to cause critical dent) is taken as the force required to cause failure.

The critical forces for trenched installation with pipe installed in soft soil conditions at 1.0 m of cover are reproduced below.

Table 3-10: Pipe Strain Limits, Trenched Installation, 1.0 m Cover, Soft Soil

Pipe Diameter (in.)	Force Required to Exceed Strain Limit lbf (kN)	Force Required to Exceed Critical Dent Limit lbf (kN)
4	56,202 (250)	36,869 (164)
12	182,095 (810)	333,167 (1,482)
20	283,259 (1,260)	503,572 (2,240)
32	494,579 (2,200)	837,638 (3,726)
44	809,312 (3,600)	158,3554 (7,044)

Curve-fitting and interpolation of the above data indicates that the force required to exceed the strain limit of 30 in. diameter pipe installed in soft soil with 1.0 m cover is 2019 kN, and the force required to cause a critical dent in 30 in. diameter pipe is 3402 kN. On this basis, the force required to cause critical strain is taken to be the force required to cause failure in a 30 in. diameter pipeline installed in soft soil, in a trench with 1.0 m cover is 2019 kN.

Chain Break Strength Analysis

Under the approach provided in DNV Report No. 2009-1115, if the force required to cause failure is less than the anchor chain break strength for a ship of a given displacement, then that ship will cause failure in the pipeline in the event of an anchor hooking event. Tabulated values of chain break strength as a function of vessel displacement are provided in DNV Report No. 2009-1115, and are reproduced below:

Table 3-11: Chain Break Loads (From DNV Report No. 2009-1115)

Vessel Class	Displacement (tonnes)	Average Chain Break Load (kN)
I	1500	411
II	3600	657
III	10000	1377
IV	45000	3610
V	175000	6487
VI	350000	9870

From curve-fitting and interpolation, ships that displace 20,570 tonnes or more will have chain break loads that are great enough to cause a critical force on the hypothetical 30 in. Straits replacement pipeline installed in a trench with 1.0 m of cover.

Failure Probability Analysis

From the preceding analysis, for Outcomes 1 and 3 (the unseated scenarios), anchor hooking can only occur for vessels that displace 93,960 tonnes (103,573 tons) or more. The anchor chains for all vessels that displace more than that amount will have breaking strengths high enough to cause a failure of a trenched 30 in. diameter pipeline, should hooking occur.

For Outcome 2 (the seated scenario), only vessels that displace 20,570 tonnes (22,675 tons) or more will have chain break loads that are great enough to cause a failure of a trenched 30 in. diameter pipeline.

Therefore, the annual probability of failure is calculated as summarized below:

- Outcome 1
  a. Count number of transits of vessels ≥93,960 tonnes (103,573 tons)
  b. Multiply value in a. by 2.0×10^{-08}
- Outcome 2
  c. Count number of transits of vessels ≥ 20,570 tonnes (22,675 tons)
  a. Multiply value in a. by 1.7×10^{-09}
- Outcome 3
  a. Count number of vessels ≥93,960 tonnes (103,573 tons)

b. Multiply value in a. by 1.7×10^{-07}

- Combined Scenarios (Outcomes 1, 2 & 3)

a. Sum values from Outcome 1 b., Outcome 2 b., and Outcome 3 b.

Results

An analysis of the NAIS data indicated that there were no ships transiting through the Straits that displaced 93,960 tonnes (103,573 tons) or more in the years 2014-2016 inclusive. The probability of failure associated with Outcomes 1 and 3 was therefore determined to be zero. For Outcome 2, the three-year average number of transits of ships displacing 20,570 tonnes was determined to range from 1,279 to 1,552, averaging 1,429 transits per year. Therefore, the average annual probability of failure was determined to be 2.43×10^{-06}. Consistent with the approach adopted in Section 2.2.1.1.1.4.1.1, for the purposes of associating failures attributed to anchor interaction with consequences in the determination of risk, the failure mechanism that has been assigned to this threat is full-bore rupture.

3.5.1.1.2.2 Failure Probability Due to Incorrect Operations

Numerous pipeline investigation analyses have shown that regardless of the direct cause, some element of incorrect operations, such as procedural, process, implementation or training factors invariably plays a role in the root causes of pipeline failure. Because it is often not possible to foresee in advance what sequence of events and breakdown in management systems and operating practices might lead to failure, there is no reliability-basis for predicting failure probability associated with this threat, and so incident data must be used to provide guidance on failure likelihood.

3.5.1.1.2.2.1.1 Approach

The same approach adopted in Section 2.4.1.1.2.1.4, which relies on industry accident statistics for hazardous liquids pipelines, was adopted to estimate failure probability associated with the threat of Incorrect Operations. This database is managed by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA), and for the years 2002-2016 inclusive, represents 76,856 mil.-y of offshore pipeline operating history. A filter was applied to exclude incidents associated with offshore platforms and wellhead flow lines. Within that record there was only one failure attributed to incorrect operations.

3.5.1.1.2.2.1.2 Results

Based on an analysis of industry incident data, the failure rate associated with Incorrect Operations in offshore hazardous liquids pipelines was determined to be 1.301×10^{-05} failures/mi.-y. Over the 3.87 mi. (6.23 km) of the hypothetical 30-in. Straits Crossing (trenched installation) replacement segment, the annual failure probability associated with this threat was determined to be 5.04×10^{-05}.

3.5.1.1.2.2.2 Combined Threat Failure Probability

Combined-threat failure probability is not used in the calculation of risk because it represents combined (leak and rupture) failure mechanisms. Therefore, this probability cannot be associated with a specific consequence for risk calculation purposes. Nevertheless, the combined-threat failure probability is included in this section for illustration purposes.

The combined annual probability of failure for the hypothetical trenched installation of a 30″ Straits Crossing replacement pipeline is determined as the statistical or calculation of the failure probabilities associated with the principal threats.

The combined annual probability of failure for the hypothetical trenched installation of a 30 in. Straits Crossing replacement pipeline is determined as the statistical OR calculation of the failure probabilities associated with the Principal Threats:

$$P_{Comb} = 1 - \left[(1 - P_{MD}) \times (1 - P_{IO}) \right]$$

Equation 3-1: Combined-Threat Failure Probability, 30 in. Trenched Installation of Straits Crossing

Where:

P_{Comb} = Combined-threat annual failure probability for the 30 in. trenched installation of the Straits Crossing

P_{MD} = Annual failure probability associated with the threat of immediate failure due to mechanical damage (Section 3.5.1.1.2.1)

P_{IO} = Annual failure probability associated with the threat of incorrect operations (Section 3.5.1.1.2.2)

Based on the above, the combined-threat annual failure probability for the 30 in. trenched installation of the Straits Crossing was determined to be 5.28×10^{-05}/y.

3.5.2 Spill Consequence Analysis

For the purposes of the environmental effects analysis, only releases of oil are considered, as NGLs (which are principally propane) do not persist in the environment. NGL releases are considered as part of the Health and Safety Consequence analysis contained in sections 3.5.2.3, 3.5.2.4 and 3.5.2.5.

3.5.2.1 Oil Spill Release Modeling

An oil outflow analysis was performed to estimate the amount of oil that could potentially spill into the Straits as a result of a failure of a hypothetical 30-in. diameter Straits Crossing replacement segment.

Estimated release volumes of oil associated with the failure scenarios considered in the Failure Probability Analysis (see Section 3.5.1) are determined in this section. These release volumes are subsequently used as input to the Oil Spill Simulation and Analysis (see Section 3.5.2.2).

3.5.2.1.1 Methodology

The methodology employed to calculate oil outflow volumes for this alternative is similar to what was used in the outflow calculation for the existing Straits pipelines (see Section 2.4.2.1.1), using Dynamic Risk Outflow software (Version 0.97.0.4465) to calculate release volumes. Further detail on the outflow calculation is provided in Appendix N.

The release sizes were determined based on the Principal Threats identified in Section 3.5.1. As outlined in that section, two Principal Threats were identified; Immediate Failure Due to Mechanical Damage, which addressed the threat of ship anchor interaction, and Incorrect Operations.

Similar to the approach described in Section 2.4.2.1.1, an FBR is assigned to the threat of anchor interaction with a pipeline, and a 3-in. (75 mm) hole size is set to represent failures attributed to Incorrect Operations.

3.5.2.1.2 Leak Detection and Isolation Time

The pipeline ROW centerline used to model the outflow volumes is based on the Straits of Mackinac bathymetry data [134] [135]. The valve locations as well as system information regarding leak detection and valve shutdown times were assumed to remain the same as in the existing Straits pipelines. The product density and viscosity values used correspond to the type of oil which is most commonly transported by Line 5, and while this information is considered commercially sensitive, values were provided by Enbridge for the purposes of this analysis. Similarly, the flow rate was based on the average annual flow rate for 2015 and 2016 (Q1 to Q3), as provided by Enbridge [96].

Table 3-12: Response Time Assumptions – 30-in. Straits Crossing Segment

	Values Assumed For Calculations			
Release Size	Detection & Response	Pump Shut-down	Valve Closure	Total Isolation Time
FBR	10 min	0.5 min.	3 min.	13.5 min.
3-in. (75 mm) Dia. Hole	30 min.	0.5 min.	3 min.	33.5 min.

3.5.2.1.3 Results

Figure 3-4 presents the elevation profile of the 30-in. pipeline crossing in the Straits, with the release locations superimposed. For the FBR scenario, the release was modeled in the center of the shipping channel, consistent with the anchor interaction failure mechanism that is associated with that release mode. For the 3-in. (75 mm) leak scenario, outflow volumes were calculated at two locations between the shipping channel and the north and south shores. Modeled outflow volumes are presented in Table 3-13.

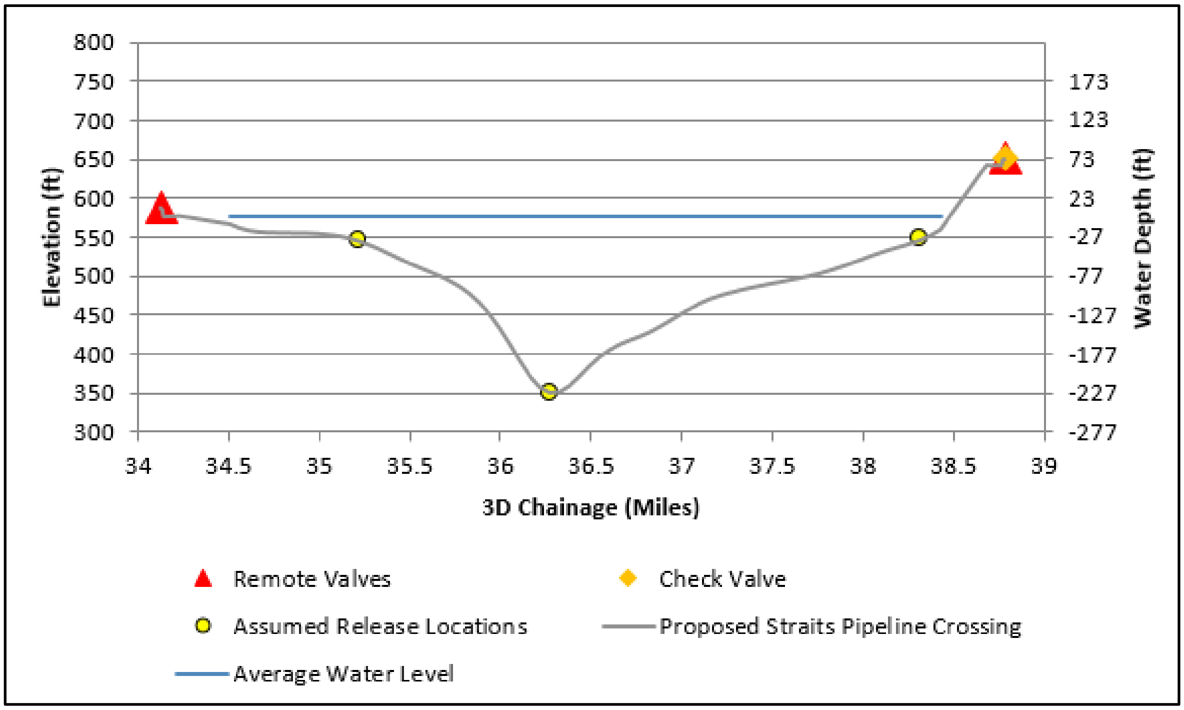


Figure 3-4: 30-in. Straits Replacement Segment Profile and Simulated Release Locations

Table 3-13: 30-in. Volume Outflow Results

Release Size	Principal Threat	Release Location	Released Volume (bbl)
FBR	Mechanical Damage	Shipping Channel	5,859
Leak/puncture (3-in. dia.)	Incorrect Operation	Shipping Channel	3,351
Leak/puncture (3-in. dia.)		Near North Shore	5,820
Leak/puncture (3-in. dia.)		Near South Shore	9,800

As illustrated in Table 3-13, the largest outflow volumes are associated with 3-in. (75 mm) holes. This is attributed to the shallower water depth at these locations, which results in lower hydrostatic pressure, and greater *drain-up* of product, which, being lighter than water, rises to higher-elevation points within the isolated pipe section.

3.5.2.2 Oil Spill Simulation and Analysis

3.5.2.2.1 Oil Spill Simulation

The MIKE powered by DHI MIKE 21/3 Oil Spill (OS) model was used to simulate spills of the Canadian Sweet Blend in the Straits based on the results from the oil spill release modeling (see Section 3.5.2.1).

The MIKE 21/3 OS model was used in deterministic and stochastic modes to determine the range of possible water surface and shoreline oiling during an entire year. Based on analysis of typical weather patterns, with consideration of periods of time with significant ice coverage, the chosen production period was set from July 1, 2014 to June 30, 2015.

The methodology and study limitations described in Section 2.4.2.1.1 are the same for the modeling of the trenched pipeline option.

From statistical analysis of the simulation results, predicted spill trajectory maps have been generated to depict the:

- Probability (risk) of a given area being exposed to spilled oil.
- Minimum time for the occurrence of spilled oil to reach a given area after the initial release of the oil.
- Maximum length of shoreline exposure (risk) and extent of exposure above a threshold.

Three hypothetical spill scenarios representing pipeline failure have been considered for the trenched 30 in. pipeline (see Table 3-14). The oil type is the same for all release scenarios.

Table 3-14: Spill Scenarios Newly Trenched Pipeline

Spill Scenario	Release Point (coordinates)	Total Outflow Volume bbl (m^3)	Spill Duration	Simulation Duration
Full rupture	Lat: 45.8185, Long: -84.7707	931.5 m3 (5,859 bbl.)	10 minutes detection/troubleshooting time + 30 seconds pump shutdown + 3 minutes valve closure + 5.83 hours drainage time	30 days
75 mm leak at northern shore	Lat: 45.8332, Long: -84.7653	925.3 m3 (5,820 bbl.)	30 minutes detection/troubleshooting time + 30 seconds pump shutdown + 3 minutes valve closure + 1 hour drainage time	30 days
75 mm leak at southern shore	Lat: 45.7899, Long: -84.7811	1558.2 m3 (9801 bbl.)	30 minutes detection/troubleshooting time + 30 seconds pump shutdown + 3 minutes valve closure + 3.5 hours drainage time	30 days

The results of the oil spill model are presented as probability maps of areas being exposed to spill occurring in water and the ZOE. Each map is composed from 120 single spill trajectories over one full year. In other words, the results do not present a single possible spill scenario but a distribution of possible spill trajectories over the year July 2014 to June 2015.

3.5.2.2.1.1 Results – Full Rupture Scenario

The oil spill simulation maps show that the majority of the spill trajectories hit the shore of the core zone within the counties Mackinac, Emmet and Cheboygan. Single spill trajectories can travel further depending on the environmental conditions existing at the time of the spill.

All result maps and the summary tables for the simulations are included in Attachment 2 (see Appendix S).

The probability of an area being exposed to the oil spill in water shows the percentage of time that an oil spill larger than 0.01 g/m^2 occurs in this area. This threshold is chosen to represent an equivalent of approximately 0.01 µm oil slick thickness.

The probability is based on analysis of combining all 120 spill trajectory simulations. Figure 3-5 shows the probability that an area is exposed to an oil spill in water based on all simulations, whereas Figure 3-6 shows the 95th percentile. Or in other words, only areas that are hit by at least six spills.

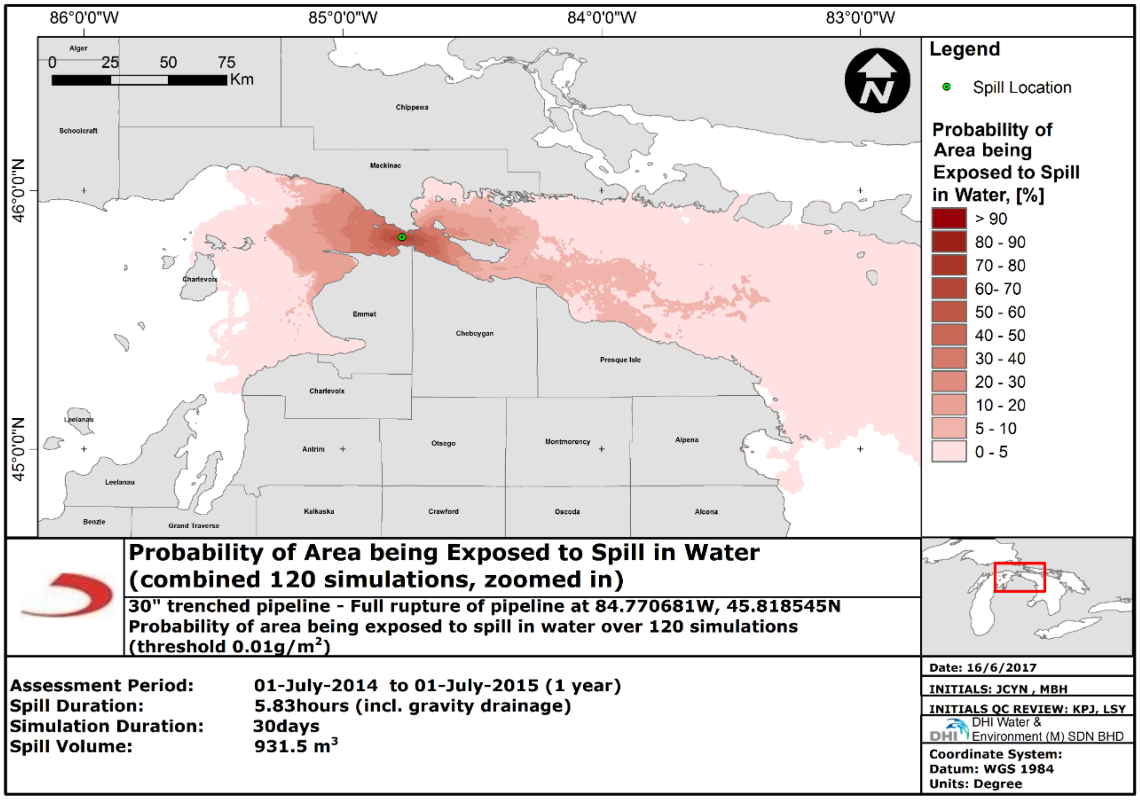


Figure 3-5: Probability of an Area being Exposed to a Spill in Water (Threshold 0.01 g/m2), Newly Trenched 30 in. Pipeline

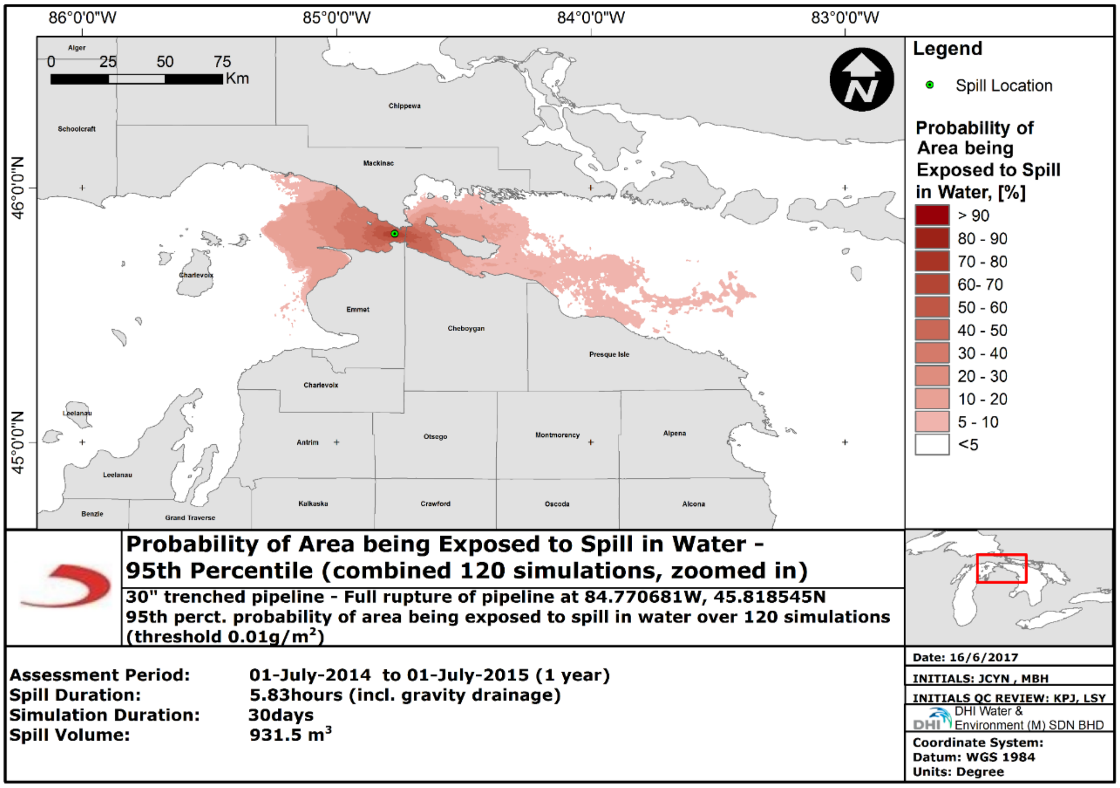


Figure 3-6: 95th Percentile Probability an Area is Exposed to Spill in Water (Threshold 0.01 g/m^2), Newly Trenched 30 in. Pipeline

ZOE maps, as shown in Figure 3-7, represent the shoreline that is being exposed to the combined oil spill scenarios. The maps show the combined result over all 120 simulations with each point depicting the maximum value realized at the shoreline over all 120 simulations. The ZOE classifies the exposure into three categories as described in Table 3-15.

Table 3-15: Thresholds Classification for Shoreline Based on Hydrocarbon Concentration (in g/m^2)

Hydrocarbon Concentration (g/m^2)	Impact Level	Description of Impact
< 1	No exposure	-
1-100	Low	• Barely visible sheen • Likely results in closure of fisheries • Fishing is prohibited • Socioeconomic impact.
100-1,000	Moderate	• Mortally impact water birds and other wildlife associated with water surface • Ecological impact.
>1,000	High	• Harmful to all birds that contact with the slick • This is used to define the zone of potential high exposure.

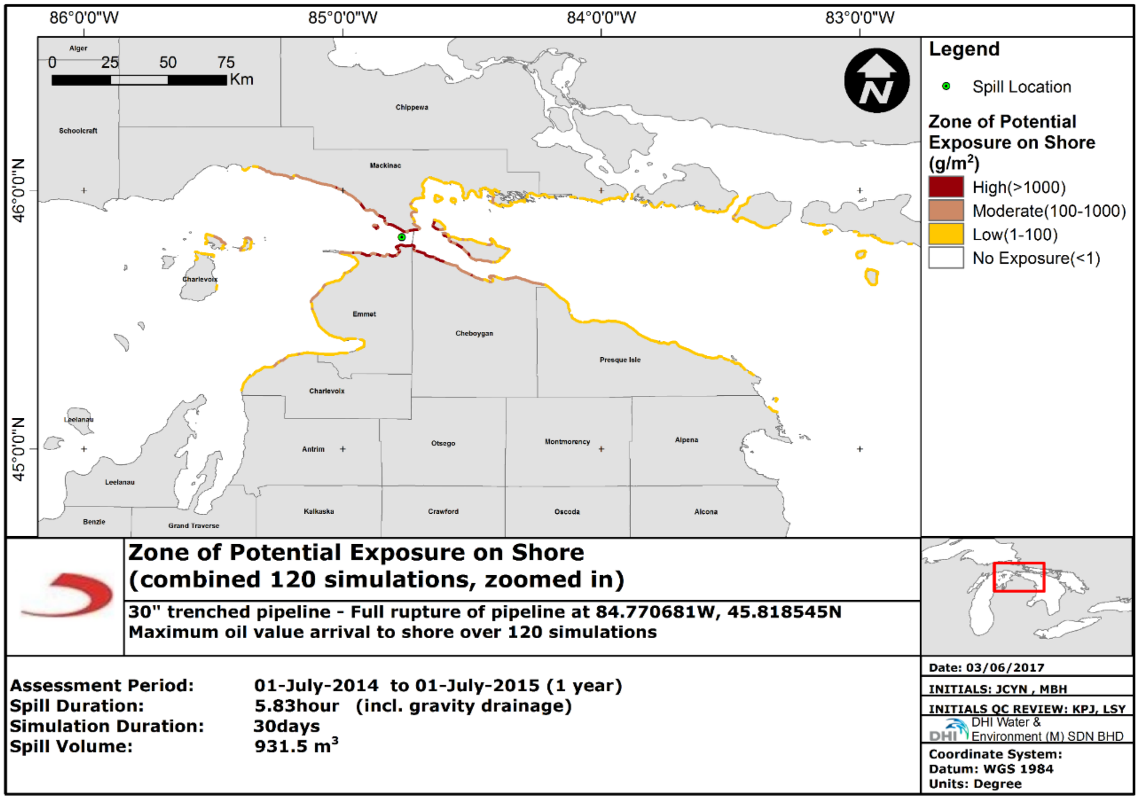


Figure 3-7: Zone of Potential Exposure on Shore (g/m^2), Newly Trenched 30 in. Pipeline

The arrival time to shore predicts the time for the oil spill to reach the shoreline after the time of the spill. All spills are mapped together meaning that the shortest arrival time to shore over all 120 simulations is shown. Longer arrival times to the shore allow for mitigation measures to be put in place to protect key receptors, compared to short arrival times where there may not be time to respond before the oil reaches shore.

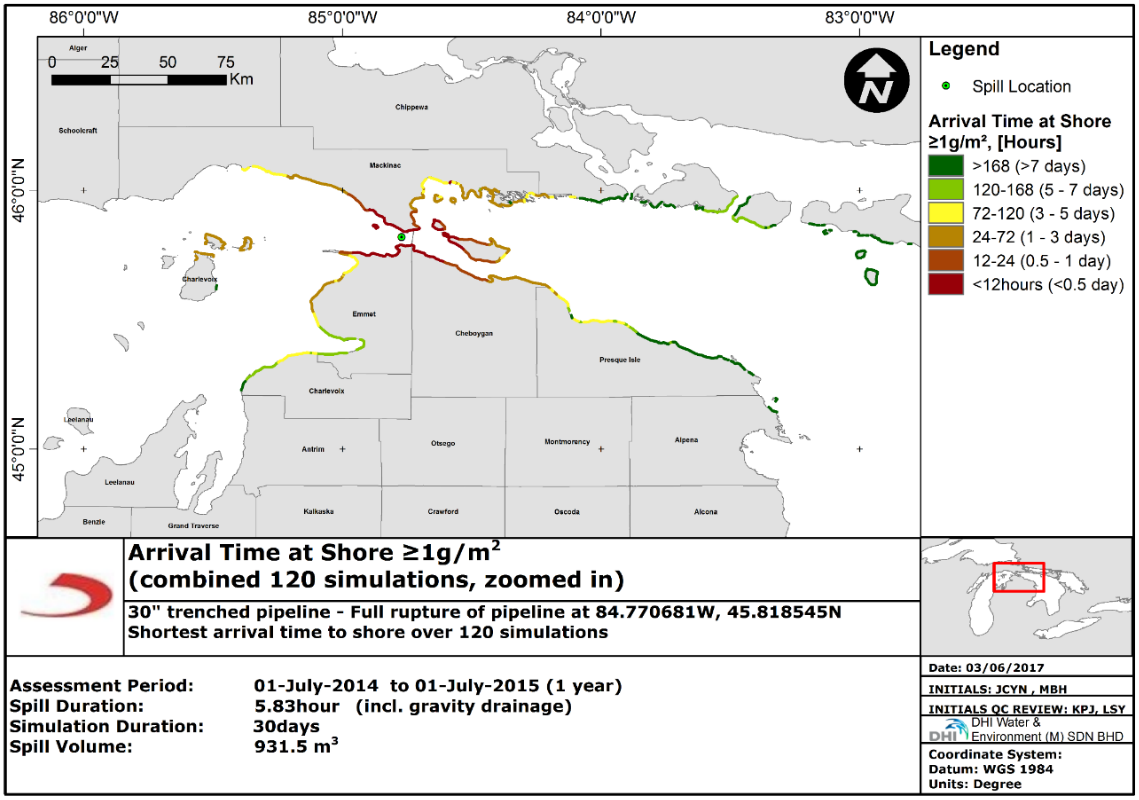


Figure 3-8: Arrival Time to Shore – Full Rupture Newly Trenched 30 in. Pipeline

Besides the assessment of the full year, seasonal-specific patterns are analyzed by dividing the year into four quarters. Each quarter includes 30 simulations, randomly distributed by time of spill. Figure 3-9 presents the probability that an area is exposed to an oil spill over the four quarters. It is apparent that during the winter season (Q3) the spill extent is the smallest. This is due to the ice cover preventing the spill from fully developing all the way to the shoreline.

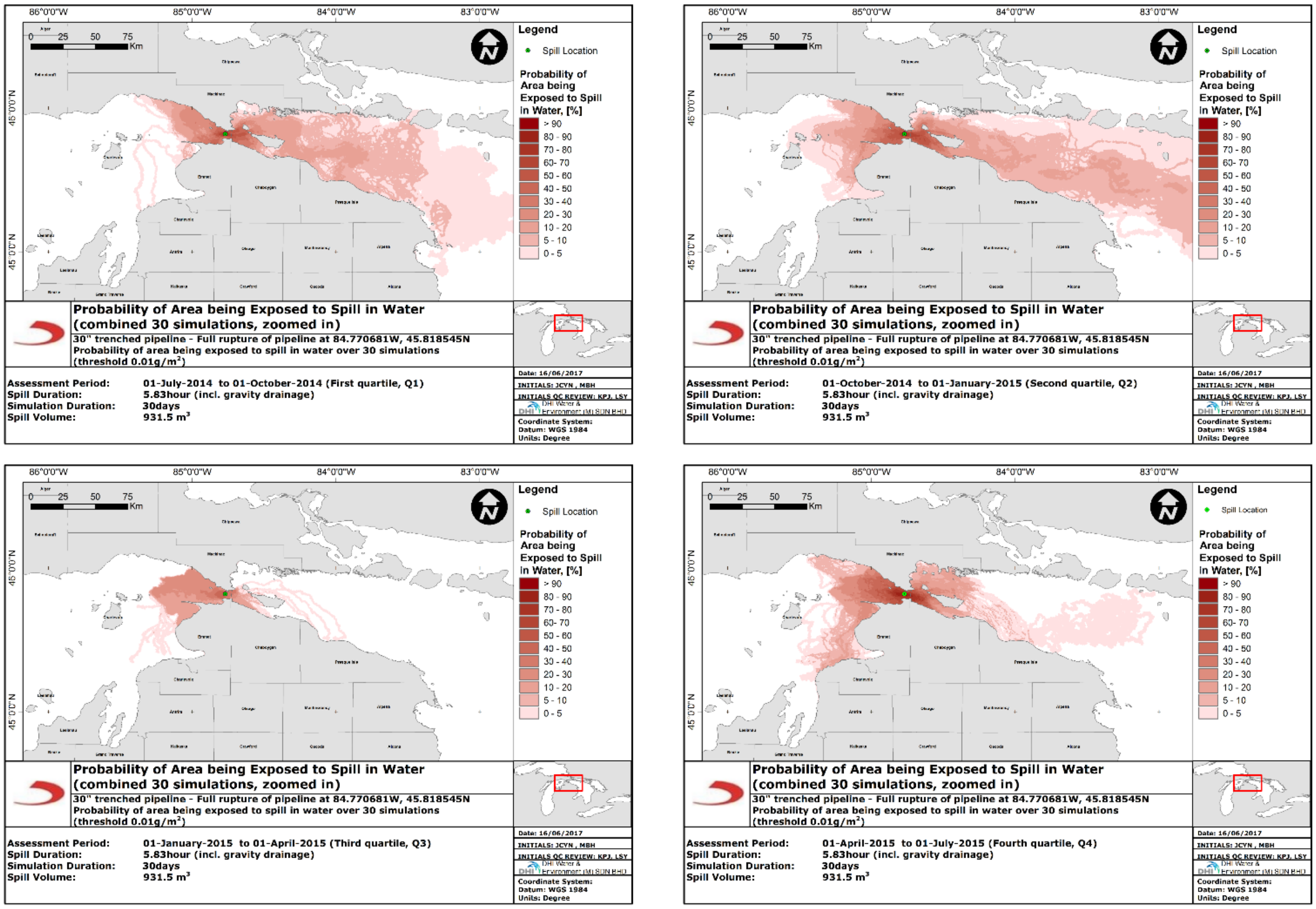
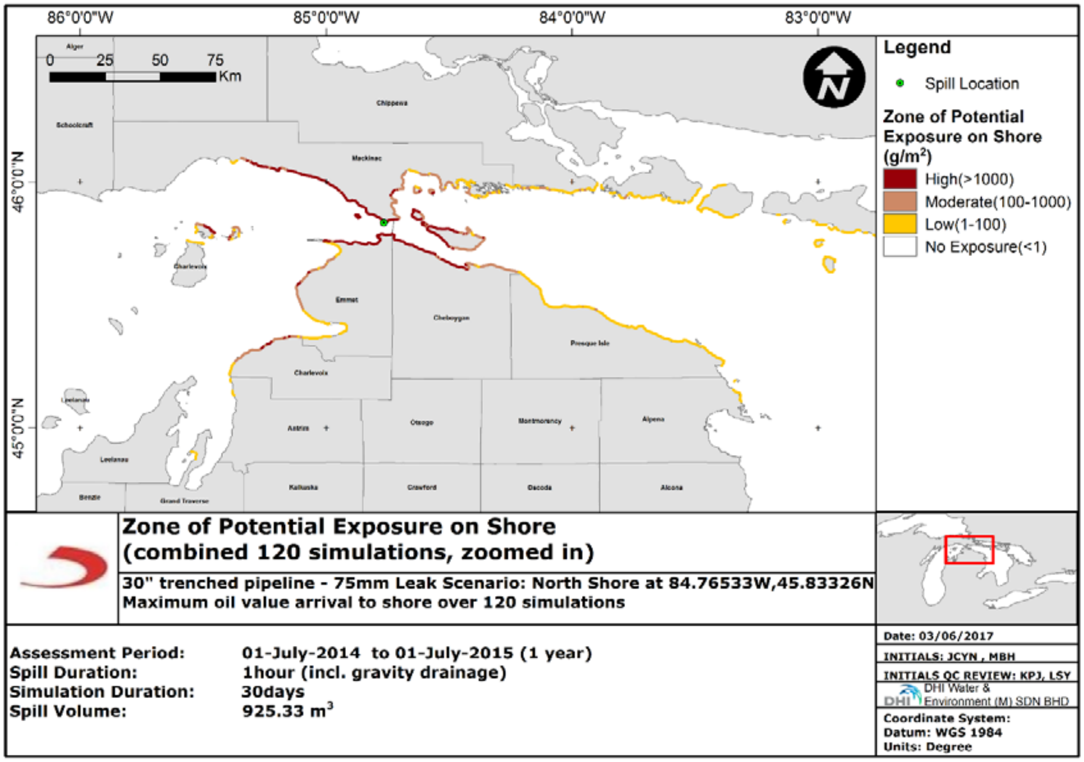


Figure 3-9: Seasonal Distribution of Probability of Oil Spill Exposure in water (Top Left: Jul-Sep/Q1, Top Right: Oct-Dec/Q2, Bottom Left: Jan-Mar/Q3, Bottom Right: Apr-Jun/Q4

3.5.2.2.1.2 Results – Leakage Scenarios

The scenarios for pipeline leakages at the northern and the southern shores are similar in terms of distribution of the spill. However, due to larger volumes spilled in the southern shore scenario, the zone of potential exposure receives higher concentrations at the shoreline for the southern shore spill scenario.



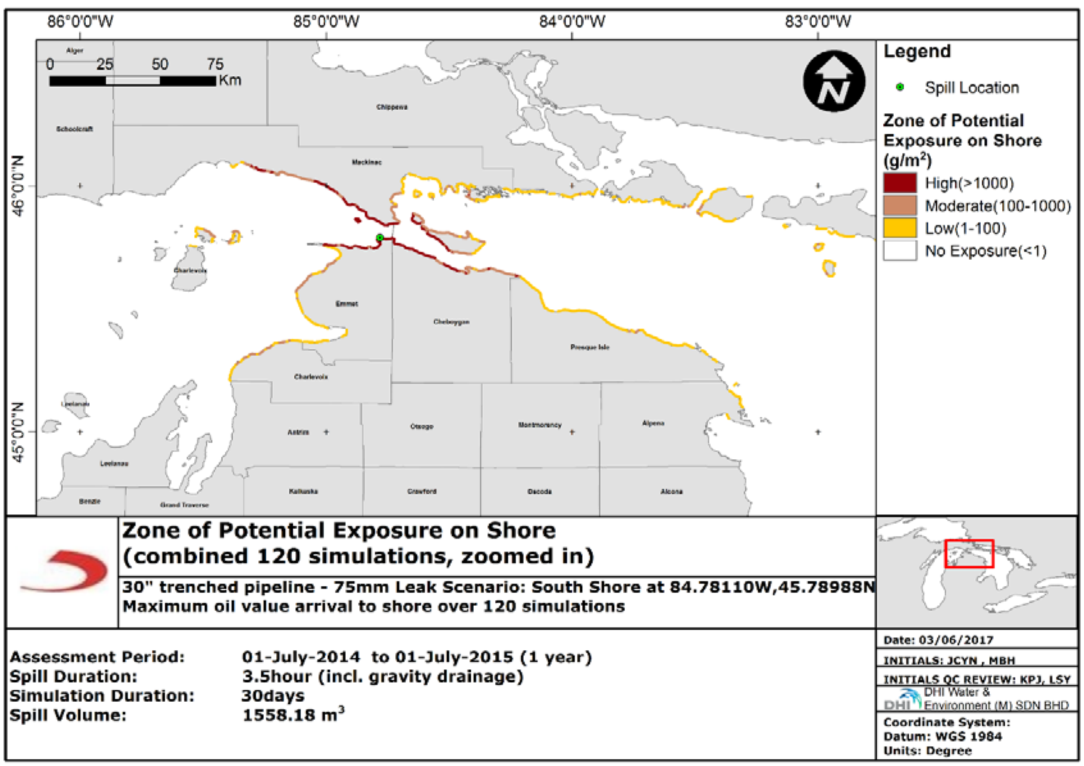


Figure 3-10: Zone of Potential Exposure (Top: Leak on the Northern Shore, Bottom: Leak at the Southern Shore)

3.5.2.2.2 Environmental Oil Spill Analysis

This section applies the spill modeling results from Section 3.5.2.2 and discusses potential impacts to sensitive ecological receptors. The methodology, impact threshold levels and the Rapid Impact Assessment Matrix approach is explained in detail in Section 2.4.2.2.2.

While the oil spill modeling clearly quantifies the dispersion of a light oil spill from the Straits Crossing pipeline, the combined above-mentioned factors suggest several ecological receptor oil exposure consequences related to a Straits Crossing spill, namely:

- Portions of the light oil will dissolve resulting in decreasing toxin concentrations towards the outer potions of the modeled spill plume or slick
- In relation to the above, a higher probability of a potentially toxic direct lethal effect to susceptible species, e.g. sessile or species unable to move away from certain habitat
- As the plume or slick disperses further and comes into contact with the shore (e.g. with likely heavier hydrocarbon chains due evaporation of lighter fractions), direct contact with vegetation and shoreline / wetland habitats
- In relation to the above, lake waters, shorelines and wetlands would experience:
    - oil smothering impacts (e.g. coating fur or feathers) to sessile species or juveniles unable to escape the spreading oil leading to stresses at potentially lethal or sublethal levels
    - oil trapped in shoreline vegetation or coating vegetation (incl. floating vegetation) which could in turn be remobilized under certain meteorological and hydraulic conditions
    - oil smoothing of certain critical habitat (e.g. foraging or spawning grounds) making them inaccessible to various species, thereby causing stresses at potentially lethal or sublethal levels
- Mobile oils in lake water that undergo longer-term emulsification', 'submergence / sedimentation' and photo-oxidation, and consequentially longer term ecological exposure to lighter oil droplets in the water column, contaminated benthic sediments and tar balls.

The sections that follow provide a brief analysis of the potential ecological impacts to representative categories of species in the Mackinac Strait, which is then followed by a RIAM Matrix illustrating the relative significance of impact to each.

It is noted that that the area of exposure is very similar for the full rupture and leakage scenarios even though the level of exposure varies. However, as the variation in exposure is all well above ecological threshold values, the actual impact does not change.

Table 3-16: Tabulated Straits Crossing Oil Spill RIAM Results

Impact on	Magnitude of Potential Impact	ES	I	M	P	R	C
Impacts on Avian communities	Major Negative Impact	-128	4	-4	3	2	3
Diving birds	Major Negative Impact	-128	4	-4	3	2	3
Wading birds	Significant Negative Impact	-64	4	-2	3	2	3
Impacts on Fish health and fitness	Significant Negative Impact	-64	4	-2	3	2	3
Impacts of Fish reproduction	Major Negative Impact	-128	4	-4	3	3	3
Impacts on Herpetofauna (physiological impact)	Significant Negative Impact	-64	4	-2	3	2	3
Impacts on Mammals	Significant Negative Impact	-64	4	-2	3	2	3
Impacts on Other general Aquatic Fauna	Significant Negative Impact	-72	4	-3	3	3	3
Impacts on Keystone aquatic fauna	Major Negative Impact	-144	4	-4	3	3	3

As apparent, in the spill-specific ZOE, a spill in the Mackinac Strait is assessed to lead to either ‘significantly’ or ‘major’ negative impacts to all ecological receptor categories. Of the included categories, however, species more likely to come into direct contact with the spill plume are ranked at ‘major’ levels of impacts. This is apparent with, for example, diving birds, fish eggs or juveniles. The category ‘keystone aquatic species’ also received an ‘major’ ranking, due to cumulative stress put on them by oil toxin concentrations and their role in overall ecosystem health.

3.5.2.3 NGL Release Analysis

The NGL release caused by a failure of the 30-in. pipeline was simulated using PipeTech software. Discharge rates predicted by PipeTech were used to assess the dispersion and travel behavior of the gas plumes in and on the surface of the water (see Section 3.5.2.4).

3.5.2.3.1 Methodology

Consistent with the approach outlined in Section 3.5.2.1 to model oil releases, NGL release sizes were determined based on the Principal Threats identified in Section 3.5.1. In that respect, an assumption of an FBR was associated with the threat of anchor interaction, and a 3-in. (75 mm) hole was associated with Incorrect Operations.

Furthermore, to account for the variation in the water depth and to investigate the impact of the release depth on the release rates, releases were modeled at different water depths along the crossing. Five representative scenarios were modeled:

1. A release from a full-bore opening in the shipping channel at a depth of 227 ft. (69 m), representing a release at the deepest location along the Straits pipeline.
2. A release from a full-bore opening in the shipping channel at a depth of 115 ft. (35 m), representing a release at a medium depth location along the Straits pipeline.
3. A release from a 3-in. (75 mm) diameter hole at depth of 227 ft. (69 m), representing a release at the deep end of the shipping channel.
4. A release from a 3-in. (75 mm) diameter hole at depth of 115 ft. (35 m), representing a release at a medium depth location along the crossing.

5. A release from a 3-in. (75 mm) diameter hole at depth of 33 ft. (10 m), representing a release at a location with shallow water depth along the crossing.

Figure 3-11 presents the release locations along the crossing.

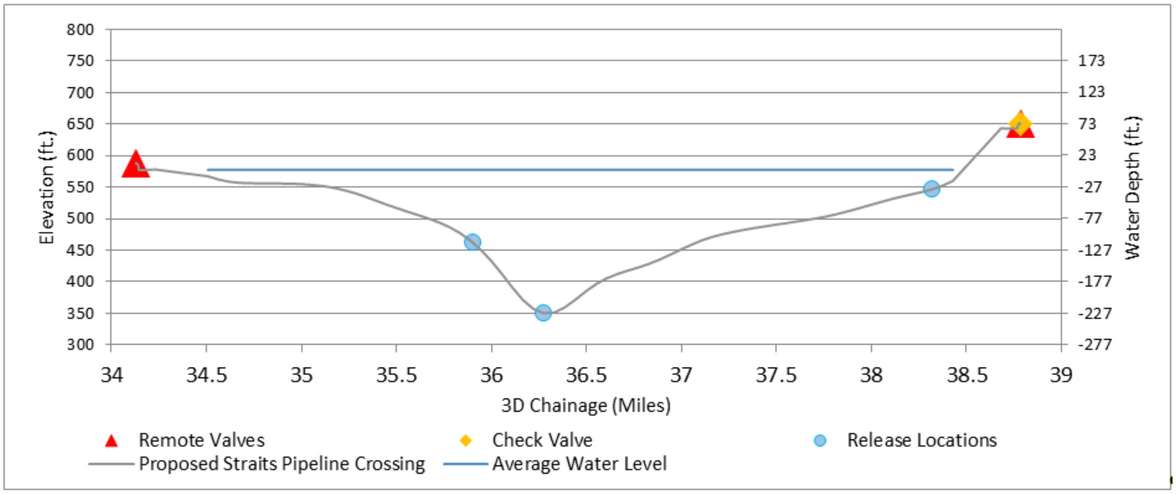


Figure 3-11: 30-in. Pipeline Profile and Release Locations

Attachment 1 (see Appendix S) contains detailed information about modeling inputs, assumptions and approach.

3.5.2.3.2 Results

Table 3-17 lists the average release rates over the initial 120 s of the release.

Table 3-17: NGL Release Rates

Scenario No.	Description	Principal Threat	Water Depth ft. (m)	Average Release Rate over Initial 120 s of Release lb/s(kg/s)
1	Full-bore failure at deep location	Mechanical Damage	227 (69)	3,613 (1,638)
2	Full-bore failure at medium depth		115 (35)	4,979 (2,258)
3	3-in. (75 mm) leak at deep location	Incorrect Operation	227 (69)	242 (110)
4	3-in. (75 mm) leak at medium depth		115 (35)	237 (108)
5	3-in. (75 mm) leak at shallow depth		33 (10)	158 (72)

As presented in Table 3-17, for full-bore events, a failure at a depth of 115 ft. (35 m) results in a higher discharge rate than a release at a depth of 227 ft. (69 m). This is due to a greater hydrostatic pressure as the water depth increases.

In the cases of the leak scenarios, the variation between the release rates at different depth is insignificant, owing to the fact that the leak involves a relatively small hole diameter of 3 in. (75 mm), resulting in an instantaneous drop to choked flow upon rupture. This leads to a very slow decompression and almost constant discharge velocity and discharge mass rate. In essence, given the very large amount of upstream inventory, the pipeline behaves much the same as an infinite reservoir. It should be noted that the mass release rate for Scenario 5 is smaller compared to those in the other leak scenarios. This is due to the larger distance between the upstream feed and the leak location resulting in lower local pressure in the pipe (see Figure 3-11).

Attachment 1 (see Appendix S) contains detailed simulation results, including the change in the discharge rate over time.

3.5.2.4 NGL Dispersion Analysis

As discussed in Alternative 5 (see Section 2.4.2.4), following a failure at the pipeline crossing, discharged NGLs could travel to the surface of the water and form a flammable cloud. An ignited flammable cloud is considered a safety hazard to the population within the area.

3.5.2.4.1 Methodology

The approach used to assess the dispersion of flammable material following a release from a hypothetical replacement of the Straits Crossing with a 30-in. pipeline is consistent with the approach used for the Alternative 5 dispersion analysis (see Section 2.4.2.4). The results of the analysis are provided in the following section.

3.5.2.4.2 Results

Table 3-18 includes the flammable distances resulting from releases at several representative depths.

Table 3-18: Flammable Cloud Distance

Release Size	Release Depth ft. (m)	Release Rate lb/s(kg/s)	LFL Distance ft. (m)	Average LFL Distance ft. (m)
FBR	115 (35)	4,979 (2,258)	8,278 (2,523)	7,729 (2,356)
	227 (69)	3,613 (1,639)	7,179 (2,188)	
3-in. (75 mm) leak	33 (10)	158 (72)	1,198 (365)	1,526 (465)
	115 (35)	237 (108)	1,690 (515)	
	227 (69)	242 (110)	1,690 (515)	

Since the depth at which a release could occur can vary based on the location of the failure, the average LFL distance was used to define the flash fire Potential Impact Radius associated with NGL releases for each release size.

Due to a higher discharge rate from a 30-in. line, the LFL distance resulting from a FBR of the 30-in. line is considerably larger than the corresponding distance for the existing line. However, the LFL cloud from a leak scenario results in a similar impact radius for both pipe sizes. As discussed previously, since the leak involves a relatively small puncture diameter of 3-in. (75 mm), the pipeline behaves similar to an infinite reservoir, and any variation between discharge rates from a 30-in. and a 20-in. line is insignificant.

As reported in Section 2.4.2.4.2 for the existing Straits segments, a thermal radiation analysis was performed to evaluate the size of the hazard zone that would be generated in the event of gas cloud ignition on the water surface. Figure 3-12 shows the maximum extent of the 5,000 Btu/h.ft^2 (15.8 kW/m^2), above which the potential for fatalities becomes significant (>1%) in the event of ignition of a gas cloud.

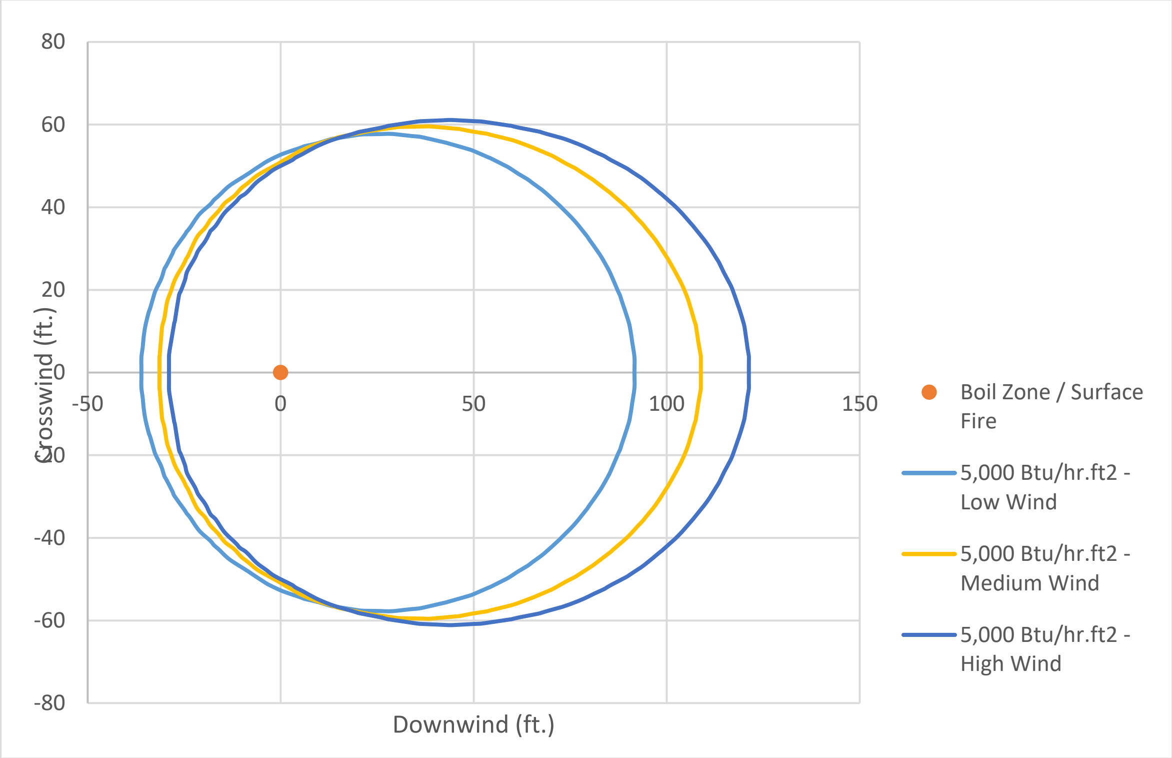


Figure 3-12: 5,000 Btu/h.ft^2 (15.8 kW/m^2) Thermal Radiation Contour

As indicated in Figure 3-12, the extent of the thermal radiation is local to the released location – less than 125 ft. (38 m) for the worst weather category. Since the safety consequence from such an event is not considered significant compared to the flame envelope of a flash fire (see Table 3-18), the latter is used as the Potential Impact Radius for the purpose of the health and safety risk assessment.

3.5.2.5 Health and Safety Consequence

As discussed in Section 2.4.2.5, the dominant health and safety hazard associated with Line 5 is flash fires from ignited releases of NGLs; all other hazards are negligible by comparison. Therefore, this is the hazard that has been evaluated for the 30-in. replacement of Line 5 through the Straits.

3.5.2.5.1 Methodology

As was described in Section 3.5.1.1.2.2.2, the principal threats associated with the 30-in. trenched installation are anchor interaction (and is associated with a FBR failure mode) and Incorrect Operations (associated with 3-in. or 75 mm holes). As was described in Section 2.4.2.5.1, due to the nature of the threat of anchor interaction, for modeling purposes, full-bore releases were located in the center of the shipping channel. For the threat of incorrect operations, however, it was recognized that there is no geographical preference for the locations of these releases. Consequently, for modeling purposes, consequences associated with 3-in. holes were determined on a length-average basis, by modeling flash fire areal extent at 200-ft. (60-m) intervals along the entire crossing, and identifying dwellings contained within each flash fire zone. Counts of individuals associated with each of the identified dwellings were then determined based on an average dwelling occupancy rate of 2.4, per US Census data [127].

An assessment of the ignition probabilities and the impacted population was conducted using the approach described in Section 2.4.2.5.1.

3.5.2.5.2 Results

To determine the safety impact of the potential flash fires on the surrounding area and the shorelines, the radius of the flammable cloud, for each release size, was superimposed on the aerial image of the Straits area. Figure 3-13 and Figure 3-14 show the extent of the flammable cloud from releases from both East and West Straits pipelines.

Figure 3-13: Extent of NGL Flammable Cloud from FBR Scenarios

Figure 3-14: Extent of NGL Flammable Cloud from 3-in. Leak Scenarios

As indicated in Figure 3-13, the LFL clouds resulting from an FBR of the pipeline crossing (located within the shipping channel), do not reach the shorelines or the Mackinac Bridge. Additionally, since the NGLs carried by the Straits pipelines are heavier than air, in case of a failure, the height reached by the flammable cloud will be relatively low, particularly as the cloud travels away from the release point. The implication of this is that in addition to the paucity of ignition sources on the lake surface, the flame envelope of a flash fire would not have a large enough vertical extent to affect individuals on the deck of a ship. Hence, the LFL cloud resulting from a pipeline rupture is not expected to pose a significant hazard to vessels traveling through the Mackinac shipping channel.

The flammable clouds produced following a pipeline leak could hypothetically reach land provided that such a leak occurred close enough to shore (Figure 3-14). Table 3-19 summarizes the potential impacts to individuals resulting from flash fires generated by FBRs as well as 3-in. (75 mm) holes from the 30-in. replacement of Line 5 through the Straits.

Table 3-19: Safety Impact of NGL Releases

Release Size	Ignition Probability	Max. No. of Impacted Dwellings	Weighted Average No. of Impacted Dwellings	Max. No. of Impacted Individuals	Weighted Average No. of Impacted Individuals
FBR	Extremely Low	N/A	N/A	N/A	N/A
3-in. (75 mm) leak	2%	10	1	24	1

3.5.2.6 Economic Consequence

The economic analysis of the spill costs involves the direct estimation of cleanup costs and a factored estimate for eventual damages. In the simplest terms:

Total Spill Costs = Total Response and Cleanup Costs + Total Damage Costs

The response and cleanup costs are a function of factors such as spill remoteness, spill size, amount of onshore oiling, type of cleanup technique used, time of year, and oil density and chemistry. Cleanup costs are also affected by the nature of onshore areas that are impacted by the spill. The damage estimate reflects potential longer term social and environmental costs associated with damages to natural resources, restoration of environmental functions, and impacts on both commercial and subsistence resource harvesting.

The spill cost modeling provides linear and non-linear functions for a number of the factors associated with the spill. The model is based on historical experience with spills in the US and with global maritime spills. The model is particularly appropriate for the estimation of hypothetical spills, as it is based on statistical findings related to global spills over the past three decades. The model excludes fines and penalties associated with a spill event.

3.5.2.6.1 Methodology

The spill cost model structure and common assumptions pertaining to spill costs in the Straits are described in Appendix R. The costs are based on the outflows described in Section 3.5.2.1, coastal characteristics of impacted shorelines, and individual characteristics of the 360 spills modeled for the various outflows.

As further described in Appendix R, the consequence of spills within the Straits were determined as a function of release magnitude (leaks and ruptures) and release location. The analysis considered cost impacts associated with several variables, including, time of year (ice vs. no ice), length of shoreline impacted, and the distribution of land-use in shorelines for those counties affected.

The Straits are designated as an HCA in accordance with the regulations established by 49 CFR Part 195 §195.450. Beyond that, the Straits are a culturally significant resource with associated tribal fishing and Treaty rights, and the oil spill factors reflect that by using higher response costs and damage levels.

Within the Straits, the core spill zone includes Emmet, Cheboygan, and Mackinac counties, in which 99% of spill material deposition would occur. The damage estimate reflects potential longer term social and environmental costs associated with damages to natural resources, restoration of environmental functions, and impacts on both commercial and subsistence resource harvesting.

As outlined in Section 3.5.2.1, in consideration of the failure mechanisms associated with both leaks and ruptures, spills caused by ruptures were modeled with a release location in the middle of the shipping channel, while leaks were modeled with release locations closer to both the north and south shores, as well as at the mid-channel location. As discussed in Appendix R, while the contingent environmental damage costs for leaks differed depending on release location, values were averaged for risk calculation purposes.

3.5.2.6.2 Results

Based on the analysis described in Appendix R, contingent total economic costs within the Straits were assessed as follows (these costs also *include* the environmental damage costs summarized in Section 3.5.2.7.2):

- leaks: $202,990,000
- ruptures: $169,950,000.

3.5.2.7 Environmental Consequence

As outlined in Section 1.9.5, for the purposes of characterizing and comparing the environmental risk between the various alternatives considered in this report, by convention, the environmental component of economic consequence has been adopted to represent environmental consequence. This measure of environmental consequence is based on a monetization of the damages, which in principle encompass the following impacts, provided that these impacts can be directly associated with a spill event:

- restoration costs of the natural environment
- a broad range of environmental damages normally included within a natural resource damage assessment (NRDA), including air, water and soil impacts.
- net income foregone in the sustainable harvest of a commercial resource
- net value foregone in the sustainable harvest of a subsistence resource, including fisheries.

The quantified elements of spill cost reflect an expected value of damages contingent upon the occurrence of an initial spill event.

3.5.2.7.1 Methodology

As further described in Appendix R, the consequence of spills within the Straits of Mackinac were determined as a function of release magnitude (leaks and ruptures) and release location. The analysis considered cost impacts associated with several variables, including, time of year (ice vs. no ice), length of shoreline impacted, and the distribution of land-use in shorelines for those counties affected.

The Straits of Mackinac are designated as a High Consequence Area (HCA) in accordance with the regulations established by 49 CFR Part 195 §195.450. Beyond that, the Straits are a culturally significant resource with associated tribal fishing and Treaty rights, and the oil spill factors reflect that by using higher response costs and damage levels.

As outlined in Section 3.5.2.1, in consideration of the failure mechanisms associated with both leaks and ruptures, spills caused by ruptures were modeled with a release location in the middle of the shipping channel, while leaks were modeled with release locations closer to both the north and south shores, as well as at the mid-channel location. As discussed in Appendix R, while the contingent environmental damage costs for leaks differed depending on release location, values were averaged for risk calculation purposes.

3.5.2.7.2 Results

Based on the analysis described in Appendix R, contingent environmental damage costs within the Straits were assessed as follows:

- leaks: $121,790,000
- ruptures: $101,970,000.

These environmental damage costs are *within* the total economic costs summarized in Section 3.5.2.6.2; they are *not* added to the total economic cost.

3.5.3 Risk Calculation

3.5.3.1 Health and Safety Risk

In risk analysis, Health and Safety risk is conventionally expressed as the annual probability of death of a person, resulting from a hazardous event [129]. The hazardous event associated with the calculation of health and safety risk for Alternative 4 is a pipeline failure; specifically, as outlined in Section 3.5.2.5, it is a pipeline failure that precipitates an ignited release of NGLs.

3.5.3.1.1 Methodology

The probabilities associated with two separate failure mechanisms – FBR and a 3-in. (75 mm) hole (leak) were determined in Section 3.5.1.1.2. Health and Safety Risk ($R_{H\&S}$, fatalities/y) was determined in accordance with Equation 3-2.

$$R_{H\&S} = F_{NGL} \times \left[\left(P_R \times P_{ign,R} \times I_R \right) + \left(P_L \times P_{ign,L} \times I_L \right) \right]$$

Equation 3-2: Calculation of Health and Safety Risk

Where:

F_{NGL} = Fraction of the time transport NGLs are transported through the Straits Crossing (= 1/6)

P_R = Annual rupture probability (see Section 3.5.1.1.1)

P_L = Annual leak probability (see Section 3.5.1.1.1)

$P_{ign,R}$ = Probability of ignition associated with a rupture event (see Section 3.5.1.1.2)

$P_{ign,L}$ = Probability of ignition associated with a leak event (see Section 3.5.1.1.2)

I_R = Weighted average number of impacted individuals from a rupture (see Section 3.5.1.1.2)

I_L = Weighted average number of impacted individuals from a leak (see Section 3.5.1.1.2)

3.5.3.1.1.1 Annual Leak and Rupture Probability

As summarized in Section 3.5.1.1.2, failure probability for the hypothetical replacement of the Straits Crossing was derived by a threat-based analysis in which the overall failure probability is derived from the following threats and their associated failure mechanisms:

- Anchor Damage: 2.43×10^{-06} per year (rupture failure mode)
- Incorrect Operations: 5.04×10^{-05} per year (leak failure mode).

Based on the above, the annual probability of rupture within the hypothetical replacement of the Straits Crossing is equal to 2.43×10^{-06} and the annual probability of a leak within this pipeline crossing is 5.04×10^{-05}.

3.5.3.1.1.2 Weighted Average Impacted Individuals

The weighted average number of impacted individuals is defined as the average number of individuals that would be within the flame envelope of a flash fire generated from an NGL release. As outlined in Section 3.5.2.5.2, the weighted average number of impacted individuals for ruptures is zero, owing to the distance between rupture release events and locations of habitation. The weighted average number of impacted individuals for leaks was reported as 1 for the entire crossing.

3.5.3.1.2 Results

From Equation 3-2, the Health and Safety Risk associated with the hypothetical replacement crossing was determined to be 1.68×10^{-07}/y.

3.5.3.2 Economic Risk

3.5.3.2.1 Methodology

The probabilities associated with two failure mechanisms – leak and rupture were determined in Section 3.5.1.1.2.

Economic Risk (R_{Econ}, \$/y) was determined in accordance with Equation 3-3.

$$R_{Econ} = F_{Oil} \times \left[\left(P_L \times \$_{Econ,L} \right) + \left(P_R \times \$_{Econ,R} \right) \right]$$

Equation 3-3: Calculation of Economic Risk

Where:

F_{Oil} = Fraction of the time Line 5 is assumed to transport Oil (= 5/6)

P_L = Annual leak probability (= 5.04×10^{-05} per Section 3.5.1.1.2)

P_R = Annual rupture probability (= 2.43×10^{-06} per Section 3.5.1.1.2)

$\$_{Env,L}$ = Economic impacts associated with a leak in the Straits (= \$202,990,000 per Section 3.5.2.6.2)

$\$_{Env,R}$ = Economic impacts associated with a rupture in the Straits (= \$169,950,000 per Section 3.5.2.6.2)

3.5.3.2.2 Results

From Equation 3-3, the Economic Risk associated with Alternative 4 (conventional trench installation) was determined to be $8,870/y.

3.5.3.3 Environmental Risk

3.5.3.3.1 Methodology

The probabilities associated with two failure mechanisms – leak, and rupture were determined in Section 3.5.1.1.2.

Environmental Risk (R_{Env}, $/y) was determined in accordance with Equation 3-4.

$$R_{Env} = F_{Oil} \times \left[\left(P_L \times \$_{Env,L}\right) + \left(P_R \times \$_{Env,R}\right)\right]$$

Equation 3-4: Calculation of Environmental Risk

Where:

F_{Oil} = Fraction of the time Line 5 is assumed to transport oil (= 5/6)
P_L = Annual leak probability (= 5.04x10^{-05} per Section 3.5.1.1.2)
P_R = Annual rupture probability (= 2.43x10^{-06} per Section 3.5.1.1.2)
$\$_{Env,L}$ = Monetized environmental impacts associated with a leak in the Straits (= $121,790,000 per Section 3.5.2.7.2)
$\$_{Env,R}$ = Monetized environmental impacts associated with a rupture in the Straits (= $101,970,000 per Section 3.5.2.7.2)

3.5.3.3.2 Results

From Equation 3-4, the Environmental Risk associated with Alternative 4 (conventional trench installation) was determined to be $5,320/y.

3.6 Risk Assessment of Pipeline Failure – Tunneling

Since the time of the original installation of Enbridge Line 5, tunneling technology has evolved to a point where it is no longer considered to be unconventional or technologically challenging to install pipelines in tunnels through mountains or across bodies of water that are too long to be considered for horizontal directional drilling (HDD). Such tunnels have advantages over other types of installation, in part, because they provide a self-contained environment that can be isolated from the natural environment by sealed concrete walls that are in turn, surrounded by bedrock.

As outlined in Appendix E, there are two main configurations of pipeline tunnels: open annulus and sealed annulus. In the open annulus configuration, the interior of the tunnel is open to the interior surface, while in the case of the sealed annulus, the opening between the pipe and tunnel wall is filled with an impermeable cement bentonite grout material. For the Straits tunnel installation design, a sealed annulus configuration was selected, since it provides redundant support around the pipe, and additional containment around the pipeline. It is deemed therefore, that this design is consistent with the objective of preventing spills from entering the waters of the Great Lakes.

Good rock conditions and minimal water inflow are anticipated at the Straits based on the Geotechnical Report (see Attachment 3 in Appendix S). During construction, any infiltration of water will be eliminated during shaft excavation by pre-excavation grouting of the bedrock outside the shaft perimeter.

In the event of material degradation within the pipe wall, either by thinning or cracking, the presence of grout would act to prevent the pipe from bulging radially by providing a continuous transfer of load/stresses, through the grout, to the surrounding concrete liner, and ultimately to the bedrock beyond. This constraint, which is the basis for permanent defect repair techniques commonly used in the pipeline industry, would act to prevent the type of localized plastic deformation that precedes failure in ductile pipeline material subject to internal pressure loading. In the absence of the development of large strains caused by outside forces such as fault movements or geotechnical hazards, this leaves the only realistic loss of containment mechanism for the pipeline to be by means of through-wall pinhole penetration without accompanying localized deformation.

In the event that a pinhole leak was to develop in the pipe wall, there are several commercially-available technologies to identify the presence of hydrocarbons in the grout annulus surrounding the pipe. The following are three of the main technologies available:

1. Transient Modeling – use of highly-sensitive mass balances, volume balances, or both to detect loss of hydrocarbons (this is likely already in place on Line 5)
2. Liquid Sensing Cables – cable(s) embedded in the grout outside the pipe, with an outer conductive polymer that swells in the presence of hydrocarbons, tripping an alarm
3. Fiber Optic System – detecting the change of temperature, which occurs when hydrocarbons escape to the area outside the pipe.

The optimal means of leak detection would need to be studied and identified during the detailed design phase of the tunnel option. Because of limited diffusion rates associated with pinhole leaks (particularly, given the presence of the multiple-layered barriers and the significant diffusion distances that would be involved in this case), leak detection technology such as those listed above, would serve to provide pre-emptive notification before products could migrate to the waters of the Great Lakes.

Given the above design considerations, there are no foreseeable mechanisms whereby the pressure membrane of the welded steel pipe might be breached, leading to migration of pipeline contents through the grout annulus, the concrete liner, the surrounding bedrock, and the overburden, leading to contamination of the waters of the Great Lakes. Other pipeline operators have selected tunneling as a means of preventing operational releases from impacting the environment, with the most recent example being the Trans Mountain twin 30-in. crude oil pipeline installation through Burnaby Mountain. Trans Mountain selected a grouted-annulus tunnel installation design, similar to that developed for the Straits Crossing. Upon completion of a risk evaluation, it was Trans Mountain's assessment that apart from one isolated zone of landslide susceptibility near one of the tunnel entrances, product loss to the surrounding environment was not feasible for the tunnel installation section [136].

For the reasons outlined above, the risks associated with the potential for a release of Line 5 products to enter the waters of the Great Lakes from a Straits tunnel crossing of a design, as proposed, is considered to be negligible, and un-quantifiably low.

4 Alternative 6

4.1 General Description

Alternative 6 assesses the potential market and economic impacts of eliminating all transportation of petroleum products and natural gas liquids (NGLs) through the segment of Enbridge's Line 5 which crosses the Straits of Mackinac. The crossing would then be abandoned and potentially all of Line 5 would be abandoned if the fragmented segments could not be effectively used.

This analysis presumes no alternative infrastructure is constructed to provide transportation of crude and NGLs from Superior through Michigan to Sarnia and that existing pipelines would not be expanded to provide additional capacity to mitigate any shortfalls resulting from Line 5 segments being taken out of service.

This analysis provides a qualitative first level impact assessment that would frame a possible broader market response. This includes the possible need to pursue alternate infrastructure development or expansions.

Neither the market disposition of supply that would be potentially stranded at Superior or the market response to securing alternate supplies to impacted refineries and petrochemical complexes outside of the State of Michigan were considered as part of the scope of analysis for Alternative 6.

Based on the above, two scenarios were considered with respect to the elimination of the Strait Crossing; Alternative 6a: Partial Abandonment and Alternative 6b: Full Abandonment.[23]

4.1.1 Alternative 6a – Partial Abandonment

Alternative 6a includes consideration of the continuing viability of the remaining fragmented segments of Line 5 as standalone pipelines that would continue to serve the receipt and delivery points in Michigan.

After the abandonment of the Line 5 Straits Crossing, a north-western leg as well as a south-eastern leg of Line 5 would remain in operation to serve the various receipt and delivery points within the state of Michigan.

4.1.2 Alternative 6b – Full Abandonment

Alternative 6b considers abandoning the entirety of Line 5.

The analyses and market impacts associated with Line 5 include separate consideration of:

- Impacts on propane supply costs to consumers in the Upper Peninsula reliant on depropanizer facilities in Rapid River for provision of propane.

[23]This report uses the terms *decommissioning* and *abandonment* interchangeably, and international usage of the terms at times varies. For clarity, the terms as used in this report do not refer to complete removal of the existing pipelines: much of the abandonment is *in place* using accepted safe procedures. Abandonment *in place* does not, however, imply that it can be used for other purposes or re-commissioned for later use at minimal expense. In some international contexts, abandonment in place is *intended* to permit recommissioning, for example, if needed for emergency purposes. The decommissioning/abandonment described in this report does not contemplate future recommissioning of pipeline terrestrial or Straits Crossing segments.

- Impacts on crude oil producers in the Lower Peninsula reliant on facilities at Lewiston for the injection of crude oil and eventual shipment to Marysville MI, Seneca NY, or Canada.
- Impacts on crude availability and supply costs to refiners serving Michigan, and potential subsequent impacts on Michigan consumers

The market impacts to consumers will generally depend on broader North American market conditions at the time of the impacts. Appendix G provides further detail on supply and demand conditions in the areas served by the Enbridge System, including Michigan. For presentation purposes, consumer impacts are represented as potential impacts on refined petroleum product prices, such as gasoline. Impacts are at times characterized as *maximum* under the assumption that none of the increased cost-of-service is absorbed by producers or refiners.

Consumer impacts are largely driven by the flow-through of supply costs to refiners. Two general impact scenarios are described.

- In the long-term it is assumed that the various costs associated with eliminated Line 5 throughput will be spread over the Lakehead System of (currently) 2600 kbbl/d. These impacts reflect a change in the cost of service of delivering crude within the Lakehead System.
- In the near-term, for analytical purposes, the report describes benchmark impacts to Detroit and Toledo refiners. These impacts reflect a change in the cost of service of delivering crude from Superior to the Midwest refineries in Detroit and Toledo. These impacts are modeled through calculating a change in the crude costs to these refiners. These refineries will potentially bear the greatest near-term impacts because they would be subject to greater apportionment impacts from the Lakehead System, and also potential apportionment of the Mid-Valley System of 240 kbbl/d capacity (when inadequate supplies through the Lakehead System become constrained).

This section also describes the direct standalone investment costs of approximately $212 million associated with abandonment of the pipeline, Straits Crossing, and facilities along the Line 5 corridor from Superior to St Clair county (see Appendix I). This decommissioning is treated as a short-term capital expenditure, with potential socioeconomic impacts in Line 5 corridor counties and Michigan as a whole; these impacts should not be construed as market impacts. The socioeconomic impacts complement those considered in subsequent analyses, which address alternative pipeline and rail routings through a different corridor of counties than the Line 5 corridor impacts reported here. In addition, a summary of the job and earnings impacts of one of the rail/truck propane delivery alternatives in the Upper Peninsula is presented to provide the reader with a potential point of comparison to some of the larger impacts associated with other facility construction and operation described in this report.

4.2 Alternative Feasibility and Design

If Line 5 were to be abandoned, fully or in part, with no additional infrastructure construction, then Enbridge would need to reconfigure and apportion its remaining system capacity to best accommodate the collective transportation service needs of its shippers. As such, shippers on all segments of the Enbridge System would be impacted if Line 5 were to be taken out of service.

Given the limited capacity availability on the Enbridge System, alternate supply sources would need to be aligned to maintain current refinery and petro-chemical operations. Alternate crude supplies could be sourced from the Gulf Coast through existing pipelines and/or rail transport.

Enbridge's reconfiguration of its system and the need to access supply from alternate sources would increase the cost of supply for refineries and may require plant or infrastructure modification and capital additions.

Alternate markets for light crude and NGLs from western Canada and North Dakota currently transported on Line 5 may be difficult to secure given the limited available pipeline capacity to other markets. To access alternate markets through pipeline expansions or by rail would likely increase the transportation costs for crude oil and NGLs currently transported by Line 5.

If, with the abandonment of Line 5, crude oil or NGLs currently transported by Line 5 are offloaded in whole or in part from the Enbridge System there would be a decrease in the Enbridge System throughput. This decrease in volume throughput would result in an increase of tariffs for the remaining volumes being transported on the Enbridge System as Enbridge would be compelled to recover certain sunk and fixed costs over a smaller volume base. This increase of unit tariffs would be allowed under normal regulatory provisions. The higher tariffs would potentially have a negative impact on netbacks for producers, a negative impact to refinery margins if the refineries directly rely on the transportation capacity on the Enbridge System for procurement of its feedstock supply, or a combination of both. Some portion of the higher tariffs may also eventually be passed along to final consumers, depending on overall adjustments in energy markets.

Any stranded or displaced crude oil and NGLs, whether at Superior or in Western Canada / North Dakota resulting from the abandonment of Line 5, would ultimately be priced into alternate markets through delivery by other pipeline systems, by rail or by tanker truck. The price offered in alternate markets together with the cost of transportation to the alternate market is likely to provide a lower netback to producers, as otherwise the producer would have already been in those markets rather than shipping on Line 5.[24]

The expansion of the Enbridge system, or other pipelines, to provide continuing access of Western Canadian and North Dakota crude oil to markets currently accessed by Line 5 would depend on securing new contractual arrangements and commitments from shippers as well as obtaining regulatory approvals.

The effects of abandoning the Straits Crossing must take into account the Enbridge Pipeline System, the interconnecting pipeline systems, and general conditions of the North American and Michigan oil and gas markets. Appendix G describes these conditions in detail.

These market impacts are wide reaching, however this analysis will focus on the impacts to the State. Analyses of Alternative 1 and Alternative 3 consider the market impacts associated with the standalone incremental costs of the transportation alternative coupled with Line 5 abandonment once those alternatives start operation.

[24] Examining these alternative markets is beyond the scope of this report.

4.2.1 Michigan Market Conditions

The sections below summarize market conditions used to frame the analysis for Alternative 6b: Enbridge Line 5 receipts and deliveries, Michigan oil production, Michigan propane supply and demand, Michigan refineries, and refined products supply and demand.

4.2.1.1 Enbridge Line 5 Receipts and Deliveries

The majority of Line 5 throughput is delivered to the Sarnia, Ontario terminal in Canada where it is then transported to refineries across eastern Canada and the US. However, Line 5 services multiple receipt and delivery points within the state of Michigan.

On the Michigan upper peninsula, Line 5 delivers NGL to the Plains Midstream depropanization facility at Rapid River, Michigan. Propane is extracted from the NGL stream and the depropanized NGL stream is returned to Line 5 for transport to Sarnia. This extraction is only a small fraction of the total volume of product transported through the line, but provides an economical fuel source for the upper peninsula.

On Michigan's lower peninsula, Line 5 receives Michigan light oil production injection at Lewiston where it interconnects with the Markwest Michigan Crude Pipeline system. Also on the lower peninsula, Line 5 delivers crude oil to the Marysville crude terminal that interconnects to the Sunoco Eastern System pipeline which transports crude from Marysville terminal to refineries in Detroit and Toledo.

Line 5 has the capacity to move 540 kbbl/d of products including NGLs, propane, and light crude.

4.2.1.2 Michigan Oil Production

In-state production of crude oil peaked in 1979 at 95 kbbl/d and has since declined. Current 2016 crude oil production is in the range 16 kbbl/d. Historically some 75% of Michigan crude production is transported by the Markwest crude oil gathering system for injection into Line 5 at Lewiston, Michigan. The remaining 25% of crude oil production is transported by truck to crude terminals for transfer to refineries.

4.2.1.3 Propane Supply and Demand

At Rapid River (located 125 mi. west of the Straits Crossing) an NGL stream is drawn from Line 5. The NGL extracted from Line 5 is fed to a depropanizer at Rapid River which produces a commercial grade propane. The remainder of the stream is gathered from the bottom of the depropanizer tower and is returned to Line 5. Propane from the depropanizer is stored at the Rapid River facility for distribution to local markets by means of the truck loading facility.

Propane demand at Rapid River varies on a seasonal basis. Peak demand is in winter, with demand falling off considerably during the summer.

4.2.1.4 Michigan Refinery

The Detroit Marathon refinery, located near I-75 in southwest Detroit, is the only crude oil refinery in Michigan. This refinery currently has a capacity of 132 kbbl/d. Recent investments permits it to process a wide range of crude slates, including heavy oil and various blends. As noted above, the Detroit refinery receives crude oil delivered from Line 5 through an interconnection into the Sunoco Eastern System at Marysville.

4.2.1.5 Refined Products Supply/Demand

The State of Michigan total refined product consumption per year is estimated at 5.7 billion gal/y. Total 2016 distillate sales in Michigan are estimated to have been approximately 1.14 billion gallons, alongside gasoline sales of 4.56 billion gallons.

Michigan relies on its Detroit refinery as well as other regional refineries located in Ohio, Indiana, and Illinois for supplies of refined petroleum products. The Lower Peninsula port cities of Detroit and Port Huron have also historically received refined petroleum products from Canada. Shipment of refined products from Canada to PADD 2 (which includes Michigan) have, however, been negligible in recent years.

4.2.2 Alternative 6a – Partial Abandonment

Abandoning the Straits Crossing would eliminate Line 5 deliveries to Sarnia. This would drastically reduce the flow within each of the pipeline segments that remain. Of the NGLs transported on Line 5, less than 5% are delivered into Rapid River. Lewiston oil injections are also less than 5% of Line 5 current throughput and do not appear to be increasing. Given the low throughput from just these volumes, Appendix K demonstrates that the flowrate on each respective segment would be too low to achieve practical pipeline velocity rates for transportation within the existing 30 in. pipeline. Accordingly, it would likely be impractical to continue to operate either of the pipe segments.

Even if pipeline velocities could be achieved, operating costs for the pipeline segments would have to be entirely borne by the Rapid River and Lewiston shippers. This would likely render these alternatives uneconomic relative to other transportation options, such as trucking.

Finally, as there is no downstream market on the segmented pipeline for the depropanized return stream of NGLs processed at Rapid River, the delivery of NGLs to Rapid River would need to be returned by truck to an NGL terminal or pipeline. This cost would further limit the viability of continued use of the Upper Peninsula pipe segment. Abandonment of this section would also undermine the ongoing viability of the depropanization facility. Therefore, local alternatives for the Upper Peninsula were assessed as alternative propane supplies rather than alternative NGL supplies.

To conclude, partial abandonment was screened out for logistical and cost reasons. The abandonment of the Straits Crossing would in effect mean the entire pipeline would be abandoned as it would be both impractical and not viable to operate either segment of Line 5 to continue to accommodate the Michigan deliveries at Rapid River or the Lewiston injections. This full abandonment scenario and its associated implications are described in Alternative 6b.

4.2.3 Alternative 6b – Full Abandonment

4.2.3.1 Rapid River Propane Supply

With the abandonment of Line 5, Rapid River would need to access an alternate propane supply to sustain its commercial function as a distribution point for local markets.

Residential propane prices for the State of Michigan for the past two winters are shown in Appendix G. Propane prices for the 2016/17 winter period are $0.10/gal to $0.25/gal higher than the previous winter. Prices in December of 2016 were in the range of $1.80/gal.

With no NGL supply to the Rapid River facility, the depropanizer facility would become stranded and would likely be decommissioned, abandoned, or removed.[25] The site's propane storage and truck loading facilities could potentially be maintained to provide for bulk receipt of propane from alternate sources and the distribution of propane to local markets. The 30,000 barrel NGL storage tank may be used for propane storage and additional propane storage tanks may be added to provide added logistical reliability of supply from alternate sources.

Figure 4-1: Rapid River Depropanizer Propane Distribution Terminal

[25]This study has not assessed the options for the optimal use of the Rapid River facility. As it is owned by Plains Midstream, such a decision will be its to make within the context of its continent-wide business decisions.

The Rapid River facility is readily accessed by truck. It does not, however, have a rail siding from which to receive propane. The nearest rail line is about 7 mi. away from the Rapid River terminal and it may be feasible to receive propane by rail if a new siding and rail Trans-Loading Facility is constructed to connect the Rapid River terminal to this rail line. However, such an analysis was considered outside the scope of the cost estimations conducted in this report. In any event, such an option – and potentially some others – would need to be competitive when compared to the backstop solution of bringing specification propane directly into the region by truck. Accordingly, this analysis focuses on alternate supplies of propane that rely on truck transport to the Rapid River storage terminal as a central distribution point.

The impacts for the Rapid River facility would include a decrease in the scope of current operations with the facility becoming simply a propane storage and distribution terminal for local markets. Increased activity would result from the trucking of propane supply to the terminal from alternate sources.

To assess the cost impact of the abandonment of Line 5 with respect to the current operations of Rapid River, the cost of alternate supply was estimated on a per gallon basis using the historical production data for the facility as a basis for analysis. This permitted capturing the significant swings in seasonal demand, and potential variations in supply costs during different months of the year.

Figure 4-2 provides the profile of recent propane demand at Rapid River terminal. Flow data on NGL net deliveries to the Rapid River Depropanizer Facility (from Line 5) were provided by Enbridge; propane rich NGLs are delivered to Rapid River and are re-injected after the depropanization process. Volumes were adjusted by an assumed 5% to derived propane production volumes.

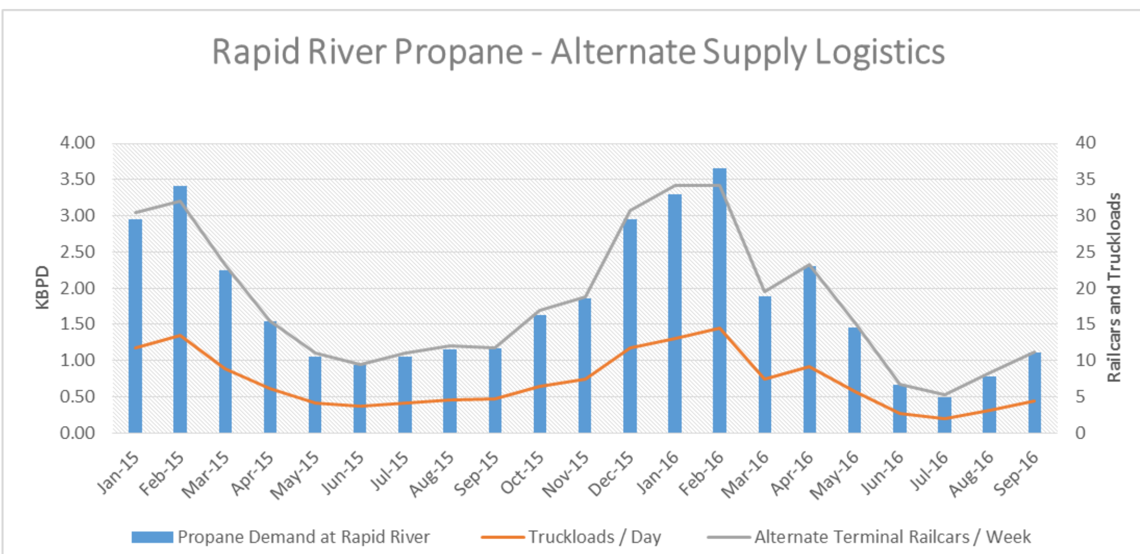


Figure 4-2: Rapid River Propane – Alternate Supply Logistics

To accommodate a similar demand profile, the analysis indicates that there would be an incremental requirement of up to 35 railcars per week in the peak winter months or corresponding peak deliveries by truck to Rapid River of 15 truckloads per day.

4.2.3.1.1 Overview of Alternate Supply Terminals

The analysis focused on identifying the incremental cost for securing propane at the Rapid River facility relative to the current cost of propane supply at Rapid River with Line 5 in service. Incremental cost includes the truck transport of propane from the alternate terminals identified plus the incremental supply cost for propane to each of the supply terminals from upstream fractionation facilities in Edmonton, Conway, or Sarnia. Table 4-1 sets out the assumptions for each of the alternate supply points and Figure 4-3 sets out the market pricing differences between the various market hubs at which propane is fractionated from NGL streams and supplied to the alternate supply points.

Table 4-1: Rapid River Alternate Propane Supply - Key Assessment Parameters

	Distance to Rapid River (mi.)	Fractionation/ Market Hub
Kincheloe, MI	150	Edmonton, AB
Superior, WI	290	Edmonton, AB
Owen, WI	240	Conway, AR
Sarnia, ON	427	Sarnia, ON

The assessment assumes that the Rapid River terminal would access alternate supply from currently operated Plains Midstream propane storage facilities at either Kincheloe, MI (supplied by rail); Owen, WI (supplied by rail); or Sarnia, ON (fractionated on site). From each of the facilities propane would be transported in bulk tanker truck trailers to the Rapid River distribution terminal.

The market hubs each have fractionation facilities at which propane is produced. Prices are determined by seasonal market demands, infrastructure constraints, and upstream production of NGLs among other supply and demand fundamentals.

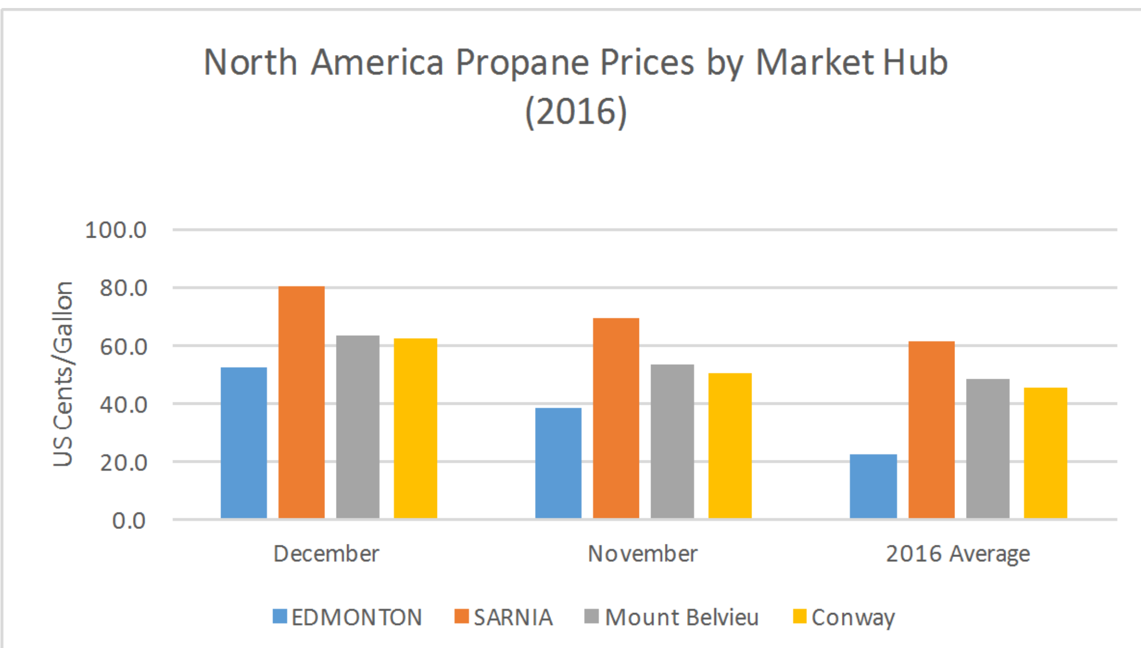


Figure 4-3: North America Propane Supply Prices

The Kincheloe, MI and Owen, WI propane terminals currently receive propane by railcars and distribute the propane to the local market by truck. The Owen, WI terminal is the larger with respect to available storage capacity.

The Superior, WI propane terminal is operated by Plains Midstream and includes an NGL fractionation facility that receives NGLs and produces propane for shipment to several propane storage facilities in the region.

The Sarnia, ON terminal is also operated by Plains Midstream. This facility receives NGLs by pipeline and train and produces propane for the local markets.

4.2.3.1.2 Rail Transportation Cost

Incremental supply costs for the alternate terminals include the cost of transporting propane to the alternate supply terminal from the nearest market hub at which fractionation facilities are located. In the case of Superior and Sarnia there is no incremental cost, whereas for the Kincheloe, MI terminal the propane was assumed to be transported by rail from Edmonton, AB. For the Owen, WI terminal, propane supply was assumed to be transported by rail from Conway, AR.

The incremental cost associated with rail supply of propane is estimated to range between $0.12/gal and $0.50/gal for the Kincheloe MI Terminal and $0.16/gallon and $0.32/gal for the Owen WI Terminal. This is shown in Figure 4-4 and Figure 4-5. The variation in the ranges largely reflects the seasonality of the propane demand while costs associated with maintaining a fleet of railcars remain fixed.

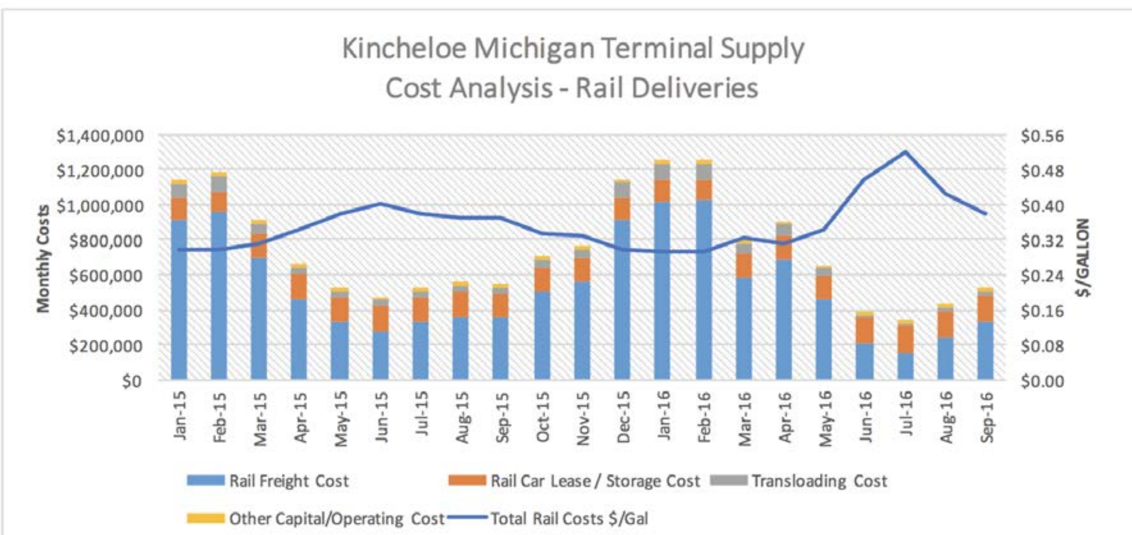


Figure 4-4: Kincheloe Michigan Terminal Supply Cost Analysis – Rail Deliveries

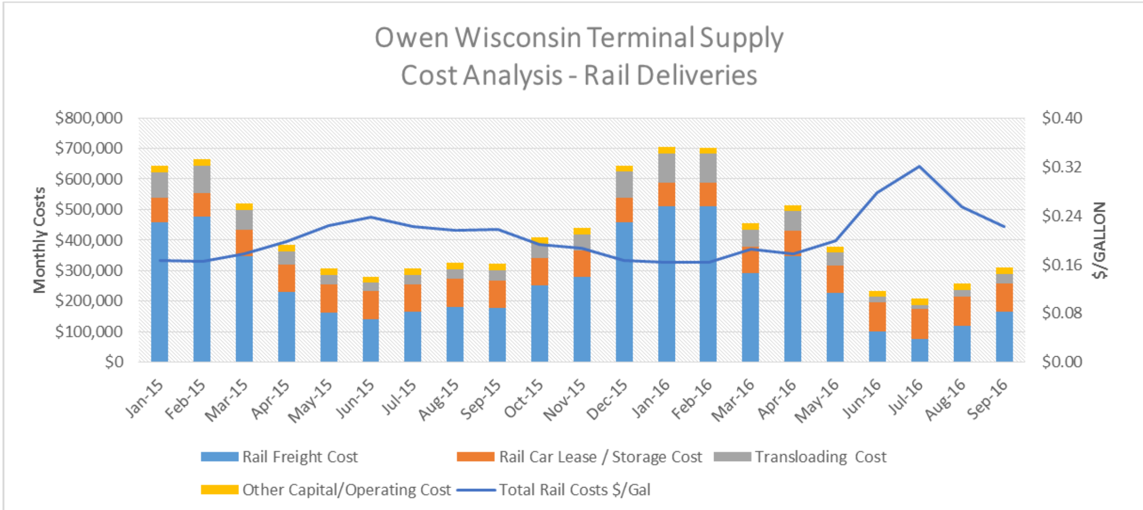


Figure 4-5: Owen Wisconsin Terminal Supply Cost Analysis – Rail Deliveries

The rail cost parameters and assumptions are shown in Appendix J. The impact analysis has not assessed the potential for any capacity limitations nor required infrastructure additions at the Kincheloe, MI or Owen, WI terminals to receive additional railcars in accommodating the transport of incremental supply to Rapid River. The cost analysis did, however, include the nominal addition of 3 x 90,000-gallon propane storage tanks at the alternate supply terminals to provide for greater logistic flexibility in the higher receipt and transloading of propane at the terminal than presently experienced.

4.2.3.1.3 Truck Transportation Cost

The cost analysis for the bulk trucking of propane supply from alternate supply terminals is shown in Figure 4-6 below. The detailed analysis and assumptions used in the trucking cost analysis are provided in Appendix J.

Unit costs for trucking will vary on a seasonal basis as volumes vary. The major cost component for trucking is the variable costs that include fuel and driver hours, which are both directly scalable to the volumes being transported. The closer terminals have a relatively lower unit cost for trucking. The unit cost for supply from the Kincheloe, MI terminal, the closest terminal to Rapid River, is $0.06/gal to $0.15/gal. Unit costs range as high as $0.30/gal for supply from the other terminals considered.

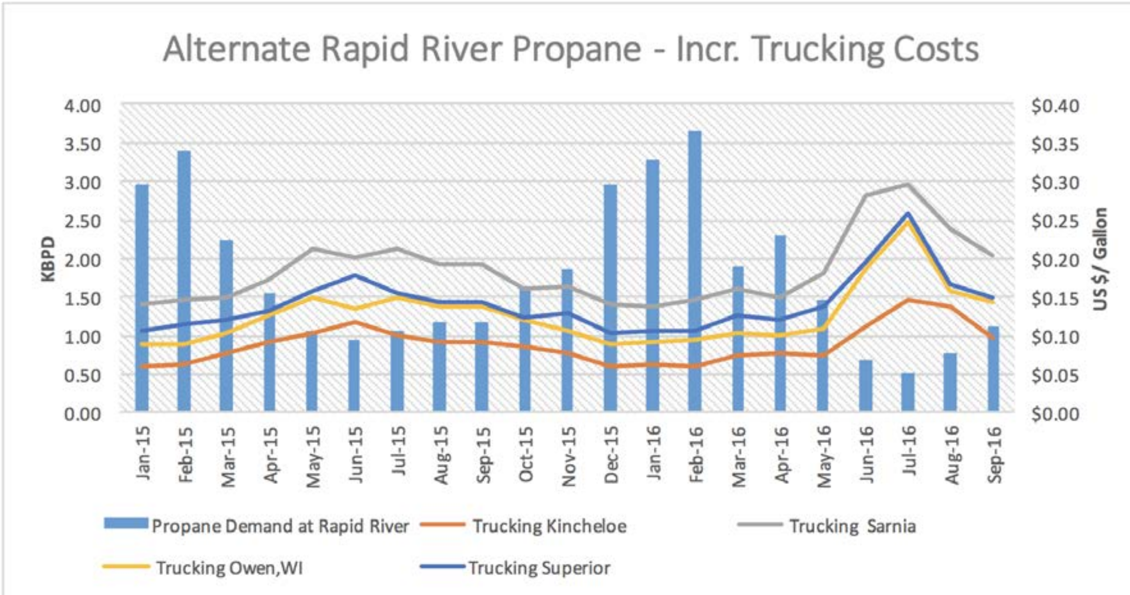


Figure 4-6: Cost Analysis – Trucking from Alternate Terminals

4.2.3.1.4 Enbridge Line 5 Tariffs

The current cost base for propane at Rapid River with Line 5 in service includes a transportation tariff on the Enbridge System. The Enbridge transportation tariff was netted out of the base cost in determining the net incremental cost for propane from alternate sources with Line 5 out of service. In the cases where propane is being delivered via rail from Edmonton, Owen, or Sarnia, the *Edmonton to Rapid River* transportation tariff of $0.08/gal was netted from the base cost. In the case where propane was accessed at Superior by truck, the Enbridge transportation tariff from Superior to Rapid River of $0.015/gal was netted from the base cost as propane is assumed to be still transported by the Enbridge System from Edmonton to Superior with Line 5 out of service.

For more details on the Enbridge system and tariffs from Edmonton refer to Appendix G.

4.2.3.1.5 Total Incremental Cost

Figure 4-7 provides the cost analysis inclusive of incremental upstream supply costs that include transport cost of propane to the alternate supply point as well as differences in market hub prices (as shown in Figure 4-6 above), less the tariff otherwise payable for transportation service on Line 5 to Rapid River.

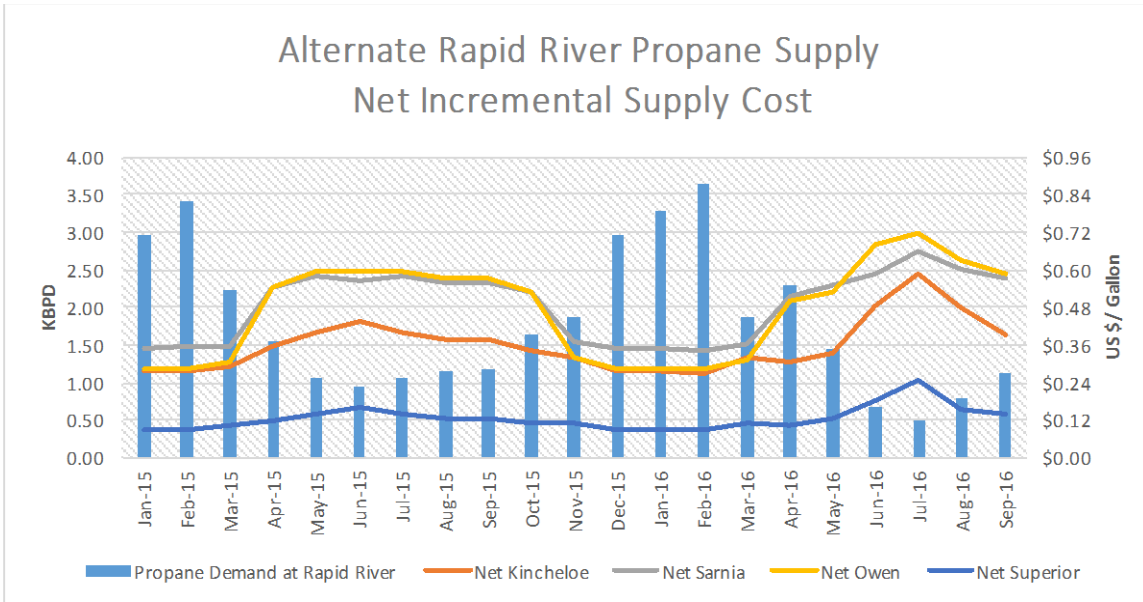


Figure 4-7: Alternate Rapid River Propane Supply – Net Incremental Cost

The analysis suggests that with all cost impacts included the alternate supply terminal that will yield the least net incremental cost is the Superior, WI terminal with total net incremental unit costs of $0.09/gal to $0.24/gal (see Figure 4-7). This reflects the relatively lower upstream supply cost associated with supply being delivered to Superior by pipeline which is significantly less costly than rail delivery. Western Canada propane prices are also relatively low and assist in reducing net incremental costs. The Kincheloe, MI terminal would be the next lowest cost alternate supply terminal with unit costs ranging from $0.28-0.59/gal (see Figure 4-7). Table 4-2 breaks out the average unit costs for the November – March period from Figure 4-7. Incremental adjusted costs for the Superior Alternative during this peak season are $0.10/gal and for the Kincheloe, MI terminal are $0.29/gal. For Owen WI the result is also $0.29/gal and for Sarnia ON it is $0.35/gal.

Table 4-2: Incremental Cost Summary – Average for November – March

Alternate Supply Option	Market Price Adjustment $/gal	Rail Costs $/gal	Trucking Costs $/gal	Adjustment for Current Applicable Tariff $/gal	Total Adjusted Incremental Costs $/gal
Kincheloe, MI Rail to Kincheloe from western Canada, truck to Rapid River	NA	0.31	0.06	-0.08	0.29
Sarnia, ON Truck from Sarnia to Rapid River	0.29	NA	0.14	-0.08	0.35
Owen, WI Rail to Owen from Conway, truck from Owen to Rapid River	0.11	0.17	0.09	-0.08	0.29
Superior, WI Truck from Superior to Rapid River	NA	NA	0.11	-0.015	0.10

Appendix J provides a table relating to the Supply of Propane to Alternate Terminals containing additional information on assumptions and calculations.

In considering alternate supply, in addition to cost impacts, supply reliability is also an important consideration. Pipeline provided supply is generally more reliable compared to trucking or rail, which are both impacted by seasonal weather impacts and other logistical challenges including road congestion. Rail and truck supply of propane demands large commitments to fixed capital assets, such as railcar and truck fleets, that must be actively scheduled to match market demand on a weekly basis and adjusted for storage inventories.

Nonetheless, the indicated range of 10¢/gal to 35¢/gal represent the expected upper bound impact on consumers of propane in the Upper Peninsula. Because these consumers represent a small amount of demand in the context of Midwest propane markets, they are most likely to bear 100% of the burden of this price increase. It can be noted, however, that this price change is similar to the year-to-year volatility experienced during normal seasonal fluctuations.

4.2.3.1.6 Socioeconomic Impacts of Kincheloe to Rapid River Propane Delivery

The economic impacts of supplying propane to the Upper Peninsula, using a combination of rail and truck transportation, have been estimated. The scenario investigated here involves propane transported by rail from Alberta to Kincheloe, Chippewa County, where it is loaded onto trucks for onward transport to Rapid River, Delta County.

The total costs of the rail/truck combination scenario are $11.2 million/y, of which $2.3 million/y represents expenditures in Michigan for rail and trucking services. Applying RIMS II economic multipliers for this industry to the $2.3 million/y results in a total of 28 (full- and part-time) jobs in Michigan with associated earnings of $1.3 million/y. The Upper Peninsula could benefit by as many as 21 jobs and $1 million/y earnings.

Table 4-3 shows consolidated results for all rounds of economic impacts because of the relatively low levels involved.

Table 4-3: Economic Impacts of Upper Peninsula Propane Delivery

Alternative 6b: Summary of Impacts: Rail and Truck Kincheloe to Rapid River		
Impact Area	Total Employment (includes direct, indirect, and induced economic impacts) (jobs)	Total Labor Earnings (includes direct, indirect, and induced economic impacts) (million $/y)
Michigan	28	$1.3
Upper Peninsula	21	$1.0
Notes: Economic contribution results were derived using BEA RIMS II multipliers.		

4.2.3.2 Lewiston Crude Oil Injections

A similar cost analysis to the one completed for propane was conducted for the continued movement of Lewiston crude to Marysville, MI in the event Line 5 was not available. Figure 4-8 shows the terminal at the Lewiston Crude Facility. The area *does not have rail access* so it is assumed that trucks would transport crude volumes. The distance of haul from the Lewiston crude battery to the Marysville crude terminal is approximately 221 mi.

Figure 4-8: Lewiston Crude Oil Terminal

Historical crude receipts onto Line 5 in 2015 and 2016 are shown in Figure 4-9.

The receipts vary from 7–12 kbbl/d, which are in turn delivered to downstream refiners. In terms of equivalent truckloads, 30 to 50 truckloads per day would be required to accommodate a similar transport demand in the future if Line 5 was not available.

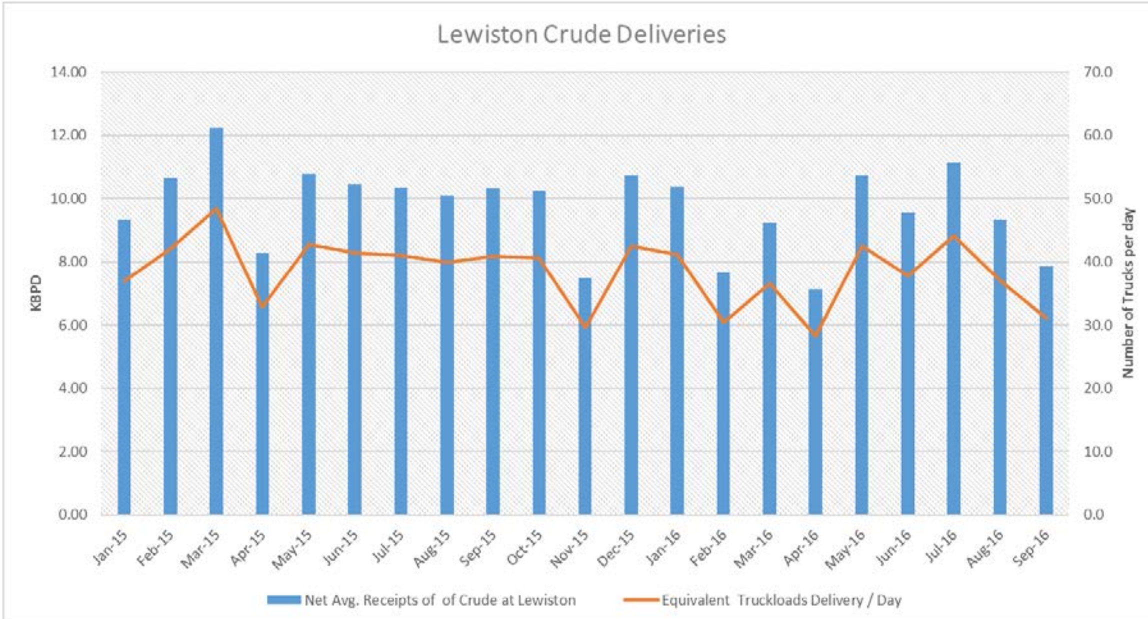


Figure 4-9: Lewiston Crude Deliveries

The costing analysis indicates that unit costs for trucking crude from Lewiston to Marysville would be in the range of $3.05/bbl, as shown in Figure 4-10 below. The transportation tariff on Line 5 during the period shown was $0.65/bbl. Accordingly, the net cost impact relative to that benchmark is estimated at $2.40/bbl. It should be noted that this tariff could face increasing volatility as Michigan oil production declines. While 2017 tariffs are approximately $0.60/bbl, lower levels of injections could put upward pressure on tariffs. For this analysis, $2.40/bbl is thus regarded as an upper bound for the potential impacts of abandonment on Lower Peninsula producers. Like the consumers of the Upper Peninsula, Michigan producers are *price-takers* who would be most likely to experience 100% of the burden of any costs in delivering their product to market. The State would potentially share some of this cost to the extent that there may be reduced tax or other obligations associated with such production by producers: such second round impacts are not addressed in this report.

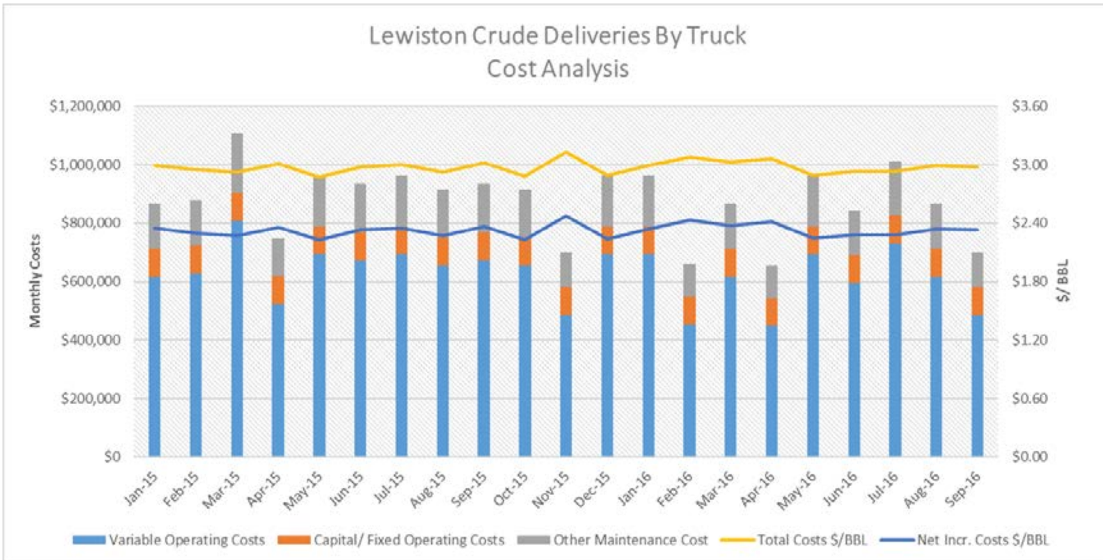


Figure 4-10: Lewiston Crude Deliveries by Truck – Cost Analysis

4.2.3.3 Impact to Refinery Supplies

In managing monthly nominations for delivery of crude oil and NGLs, Enbridge allocates available capacity in accordance to shipper requirements. If there are capacity constraints on any segment of its pipeline, Enbridge would look to shippers to reduce their respective nominations accordingly. The procedures through which volumes are allocated to available capacities and shipper nominations are aligned: the procedures are generally known as apportionment. Apportionment simply allocates available capacity to specific delivery points through the pro-rationing of capacity based on respective delivery point nominations.[26] To minimize impacts to their respective operations, a shipper would presumably nominate its maximum contract amount to obtain the highest prorated capacity at the delivery point under an apportionment scenario.

With Line 5 out of service there will be an Enbridge System capacity constraint in meeting shipper requirements. Accordingly, an apportionment of available capacity will prevail, in particular, on Line 78 that provides for transport of crude oil from Griffiths to several delivery points that impact available feed supply to the Michigan refineries. This would cause potential crude oil shortfalls to Detroit and Toledo refineries.

From Line 5 and Line 78 Enbridge's total available capacity to delivery points in Michigan and Ontario downstream of Griffith is 1110 kbbl/d. While maximum capacity from Stockbridge to Sarnia is listed at 500 kbbl/d, this is accompanied by a significant take-off at Stockbridge which reduces the overall throughput going to Sarnia. Therefore, if Line 5 is removed from service, Line 78 capacity of 570 kbbl/d would be the limit on capacity available to shippers downstream of Griffith and has been used in apportionment calculations. In this analysis, it was also assumed that the segment of Line 5 from Marysville to Sarnia will remain operational to provide crude transport from

[26] There are considerations other than total volume, notably, some adjustments or limitations may be associated with quality of crude. The analysis assumes no limitations or adjustments associated with quality of crude.

Sarnia to the Sunoco Eastern System pipeline or that there is an equivalent interconnect at Marysville to Line 78 for transfer of crude to the Sunoco pipeline.

The resulting apportionment of the Enbridge available capacity with and without Line 5 in service is provided in Appendix J.

The maximum nomination is based on nameplate capacities of the facilities downstream of Line 5 delivery points; these amount to 1,233 kbbl/d. Apportionment of these nominations is done on a prorata basis using current facilities of Line 78 and Line 5 to a limit of 1,110 kbbl/d (570 kbbl/d for Line 78 and 540 kbbl/d for Line 5). In the absence of Line 5, all final demand points would still receive some amount of the nominations but would be constrained to the total Line 78 capacity of 570 kbbl/d.

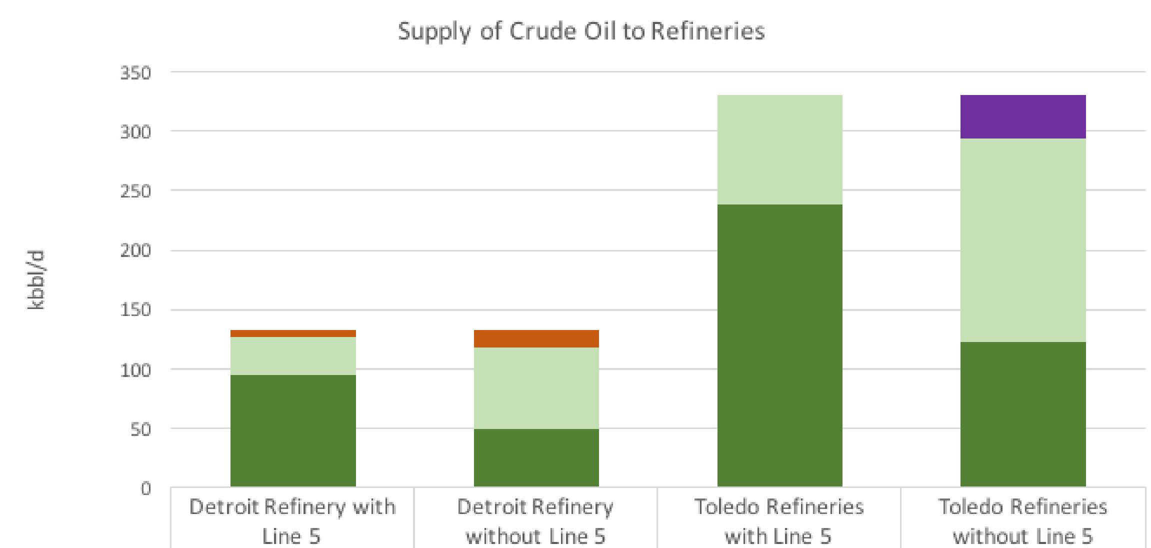
A maximum take-away capacity/nomination was estimated based on the lesser of downstream refinery capacities at the delivery point or the take-away capacity of the connecting pipeline at the delivery point. The difference between capacity with Line 5 in service and without Line 5 in service is taken as the net impact to each of the delivery points in the scenario where Line 5 is unavailable.

The estimated apportionment of available capacity on Line 78 with Line 5 removed from service indicates that available supply from the Stockbridge and Marysville, MI delivery points is estimated to total 171 kbbl/d. These delivery points provide feedstock to the Toledo and Detroit refineries. Comparing this to available capacity of 333 kbbl/d with Line 5 in service, there is a decrease of 162 kbbl/d.

The available Enbridge supply capacity for Sarnia refineries and delivery points east of Sarnia would also correspondingly decrease by 378 kbbl/d with Line 5 out of service.

In addition to crude oil supply from the Enbridge System, the Detroit and Toledo refineries would access additional supplies from the Mid-Valley Pipeline (total capacity of 240 kbbl/d) as well as through truck and rail deliveries

Figure 4-11 shows the supply availability to the Detroit and Toledo refineries presuming the total supply is available from the Enbridge System and the Mid-Valley Pipeline with remaining shortfalls being made up through truck and rail deliveries.



	Detroit Refinery with Line 5	Detroit Refinery without Line 5	Toledo Refineries with Line 5	Toledo Refineries without Line 5
Truck	5	15	0	0
Rail	0	0	0	36
Mid-Valley	32	69	92	171
Enbridge	95	49	238	122

Figure 4-11: Detroit/Toledo Refineries - Available Supply Options to meet Refinery Capacities

With Line 5 decommissioned, it is estimated that the decrease in supply availability from the Enbridge System of 162 kbbl/d to the Detroit and Toledo refineries will be offset through an increase in deliveries by the Mid-Valley Pipeline of 116 kbbl/d, by trucking of 10 kbbl/d from Lewiston, MI to the Detroit refinery, and by rail deliveries of 36 kbbl/d to the Toledo refineries. The Detroit refinery would receive an additional 37 kbbl/d through apportionment nominations over the Mid-Valley pipeline.[27]

4.2.3.4 Impact to System and Refinery Costs

4.2.3.4.1 Long-term Cost Impacts in Lakehead System

The abandonment of Line 5 will result in reduced system throughput. In addition, Enbridge will incur abandonment costs. For analytical purposes, the current system throughput of about 2600 kbbl/d is taken as a reference. Excluding Line 5 capacity leaves residual capacity at 2060 kbbl/d (corresponding to initial system capacity of 2600 kbbl/d less Line 5 capacity of 540 kbbl/d).

The most significant impact of abandonment will be the increase in tariffs because of decreased throughput. This impact involves continued payment of all existing Lakehead System infrastructure, fixed operating costs and overheads (e.g., insurance, general administration), and non-Line 5 variable costs. Payments, however, must be recovered over throughput which has decreased from 2600 kbbl/d to 2060 kbbl/d. All other things

[27]Recall that the Marathon refinery has 132 kbbl/d capacity and that the Toledo refineries have 330 kbbl/d of capacity. This equates to potential nominations of 462 kbbl/d against 240 kbbl/d of capacity on the Mid-Valley system. The Detroit refinery would receive its prorata share of the capacity, which is 132/462 x 240 kbbl/d or 69 kbbl/d. The Toledo refineries would receive the balance available to them according to their share: 330/462 x 240 kbbl/d or 171 kbbl/d.

equal, this equates to a unit cost increase across *all volumes shipped* of 26.2%. If distributed evenly over every tariff in the system, this implies an increase of $0.39/bbl to the current Superior–Sarnia tariff of $1.50/bbl. Other customers on the Lakehead System (in the Chicago area, for example) would also experience similar percentage increases.

In addition, abandonment costs would be added to the rate base. Appendix I shows abandonment costs of all segments of Line 5 from Superior to the Sarnia/Marysville area to be $212 million. At a 6%/y discount rate amortized over annual throughput of 2060 kbbl/d, the incremental contribution to all tariffs on the system would equate to about $0.018/bbl. This is just over 1% of the current Superior–Sarnia tariff of $1.50/bbl.

Once abandoned, there would also be some cost savings through lower operational costs. Many of the operating costs of Line 5 are variable in the long-term: as described in Section 2, current operations contribute to direct employment, as well as to payments for maintenance supplies and services, energy, recurrent replacement capital expenditures, and pipeline taxes. In total, these costs have been estimated to be $95 million/y. Removal of Line 5 variable costs across the Lakehead System, and applied to 2060 kbbl/d of throughput, equates to a cost-of-service reduction of about $0.10 - 0.12/bbl on all system throughput. The lower level reflects that abandonment monitoring activities may incur some ongoing obligations for some time to ensure safe conditions.

A long-term net impact on system transportation tariffs is thus expected to be of the order of $0.40/bbl once abandonment has occurred; this impact may decline to approximately $0.30/bbl over the longer term. The higher level, yielding costs of $1.90/bbl for Superior-Sarnia, provides a benchmark against which other alternatives might be considered.

4.2.3.4.2 Near-term Cost Impacts to Detroit and Toledo Refineries

Cost impacts in various sub-systems may create local pricing distortions and this would be most likely in the event of constrained capacity. This section considers the potential cost impacts in the near term that may arise from the capacity constraints and apportionment addressed in Section 4.2.3.3. Because of their proximity to each other, their crude sourcing through similar systems, and their markets in the same area of PADD II, this section treats the Detroit/Toledo refineries as a consolidated cluster. It is acknowledged that this is a simplifying assumption, as each individual refiner will have independent supply arrangements which may differ at the margin than those assumed here. The treatment as a single cluster, however, is consistent with equilibrium market conditions and provides a reasonable benchmark for estimating impacts under such conditions. To reflect potential short-term pricing volatility a sensitivity analysis is also conducted.

The Detroit and Toledo refineries will incur extra costs to access additional supplies via other pipelines, rail, or truck from alternate supply sources which may also include a higher commodity price relative to supplies currently provided by Line 5. These costs together with the net Enbridge costs are shown in Table 4-4 below.

Table 4-4: Incremental Crude Supply Costs for Detroit and Toledo Refineries

	With Line 5	Without Line 5	Incr. Cost ($ million)
Enbridge Pipeline Supply			
Volume (kbbl/d)	333	171	
Tariff ($/bbl)	$1.50	$1.50	
	Tariff Increase	$0.40	
Cost ($ million/y)	$182.32	$118.59	–$63.73
Mid-Valley Pipeline Supply			
Volume (kbbl/d)	124	240	
Tariff ($/bbl)	$1.07	$1.07	
Total ($ million/y)	$48.43	$93.73	$45.30
Rail Supply			
Volume (kbbl/d)	0	36	
Rate ($/bbl)	$10.00	$10.00	
Cost ($ million/y)	$0.00	$160.40	$131.40
Trucking			
Volume (kbbl/d)	5	15	
Rate	$2.40	$2.40	
Cost ($ million/y)	$4.38	$13.14	$8.76
Total Annual Incremental Feedstock Cost			$121.73
Refineries Total Capacity (kbbl/d)			462
Operating Factor			95%
Total Annual Feedstock Supply (million bbl/y)			160.20
Incremental Unit Cost per Barrel ($/bbl)			$0.76

The net incremental cost for crude oil feedstock for the combined Detroit and Toledo refineries is estimated at $0.76/bbl. This assumes that market prices are in equilibrium within the region.

Price differentials may arise within local or continental energy markets, particularly where volume throughput is apportioned or constrained in some regions. A price premium of $1/bbl on the incremental throughput from the Mid-Valley Pipeline System or from rail (152 kbbl/d) would increase the incremental unit cost per barrel to Detroit and Toledo refineries by $1.11/bbl. A price premium of $3/bbl on the incremental throughput from Mid-Valley or from rail would increase the incremental unit cost per barrel to Detroit and Toledo refineries by $1.80/bbl.

4.2.3.4.3 Impacts on Michigan Consumers

The incremental feedstock costs for the refineries may translate into higher refined product costs across the state, such as gasoline and distillate. This will be driven by local supply conditions, which we ascribe for the purposes of this analysis to the Detroit/Toledo refineries. Assuming an 85% yield of refined products per barrel of crude feedstock to the refinery, the incremental $0.76/bbl associated with the system impacts translates to an incremental cost for refined products of 2.13¢/gal. As noted previously, the State of Michigan total refined product consumption per year is estimated at 5,700 million gal/y.

Accordingly, if the crude supply costs are passed through to the consumer of refined products, the impact to the State of Michigan is estimated at $121 million/y, assuming all refined products consumed in the State of Michigan are provided by the Detroit and Toledo refineries.

The sensitivity to market price differentials for oil supply might magnify any apportionment impact. For every extra $1/bbl paid for supply through Mid-Valley and rail, average feedstock supply costs increase by approximately $0.35/bbl: equivalent to an increase of 1.0¢/gal to consumers if the entire cost were passed on. As it is not possible to predict the level of volatility in regional prices that may occur after Line 5 abandonment, the results presented in this report focus on the summary cost of service impact that can be expected. Impacts may exceed the reference case impacts of 2.13¢/gal noted above; for example, a $5/bbl market price differential in continental markets would render refined product prices approximately 7¢/gal higher than they otherwise would be.

4.2.3.5 Summary of Potential Alternative 6b Market Impacts

The assessment carried out for Alternative 6b focused on the impacts to energy facilities within the State of Michigan that rely on Line 5 for the receipt or delivery of commodities to their respective facilities. The alternative transportation chosen and estimated costs are discussed in Table 4-5 below.

Table 4-5: Alternative 6b Cost Summary

Affected Facility	Alternative Transportation	Estimated Unit Cost	Estimated Annual Cost
Rapid River	Trucked from alternate terminals to Rapid River	$0.10 – $0.35/gal of propane	$3.07 million/y minimum (2 kbbl/d)
Lewiston Oil Production	Crude oil trucked from Lewiston Crude Facility to Marysville Terminal	$2.40/bbl	$8.76 million/y minimum (10 kbbl/d)
Crude oil feedstock for Detroit and Toledo Refineries	Apportionment of Enbridge Line 78 capacity, incremental supply from Mid Valley Pipeline, and trucking of Lewiston oil production.	$0.76/bbl	Detroit & Toledo: $121 million/y (Detroit apportioned 49 kbbl/d from Enbridge system) (Toledo apportioned 122 kbbl/d from Enbridge System)

Additionally, the incremental feedstock costs for the refineries may translate into higher refined product costs for gasoline and distillates of 2.13¢/gal throughout the State of Michigan. Assuming the incremental cost is passed through to Michigan consumers, who consume 5,700 million gal/y, this cost equates to $121 million/y.

A long-term net impact on system transportation tariffs is expected to be of the order of $0.40/bbl (equivalent to 1.12¢/gal including adjustments for refinery yields) once abandonment has occurred; this impact may decline to approximately $0.30/bbl (0.84¢/gal adjusting for yields) over the longer term. The higher level, yielding costs of

$1.90/bbl when added to the current Superior-Sarnia tariff, provides a benchmark against which other non-pipeline alternatives might be considered.

4.3 Socioeconomic Impacts of Line 5 Abandonment

4.3.1 Introduction

The abandonment of Line 5 (Alternative 6) involves – in Michigan only – 545 mi. (877 km) of pipeline and 13 pump stations that in total cover 59 acres (24 ha). Most of the land cover affected by Line 5 pipeline abandonment is forest (331 mi.), and cultivated land (108 mi.); only 5 mi. falls in urban areas; and there are 156 crossings (road, river, rail, and airport). The abandonment strategy has the pipeline abandoned *in place*, with 13 mi. filled with concrete. The Straits Crossing would be filled with water (see Appendix I).

Over the length of the pipeline work crews would be purging the line of hydrocarbons. Where the line comes aboveground, it would be cut and sealed. Pump stations would be cleaned and purged, all surface equipment removed and the land reclaimed.

Nineteen counties along the Line 5 ROW would be affected by abandonment activities: seven in the Upper Peninsula; the remainder in the Lower Peninsula, from Emmet southeast towards Saginaw Bay and St. Clair County. Economic impacts (jobs, income, output) of construction are discussed in Section 4.3.2. Other socioeconomic impacts are summarized in Section 4.3.3. All socioeconomic impacts associated with Alternative 6 are discussed in greater detail in Appendix Q.

The impacts described in this section are standalone and not necessarily dependent on any other Alternative. The assessment of Alternatives 2, 1, and 3 in the following sections exclude the impacts described here, but those alternatives would be associated with the impacts herein. Note that Alternative 2 and Alternative 3 involve no construction in Michigan, and that Alternative 1 (Southern Pipeline) involves construction and operation but not in the same corridor of counties or group of Prosperity Regions in which Line 5 abandonment takes place.

4.3.2 Construction Cost Economic Impacts

Economic multipliers (BEA RIMS II) have been used to estimate the economic impacts of abandoning the whole of Line 5 (see Table 4-6). The construction cost is estimated to be $212 million: this includes abandonment of the terrestrial segments of the line, and the Straits water crossing segment. As 91 mi. (147 km) of Line 5 are located in Wisconsin, some of the terrestrial expenses would be incurred in that state. Accounting for only those expenses related to Line 5 in Michigan means that abandonment of Line 5 terrestrial and Straits Crossing segments amounts to some $184 million in construction spending.

The project would generate about 2200 (full- and part-time) jobs in Michigan: about 1000 directly, and another 1200 indirectly from the indirect spending on materials and services by supply contractors to the project, and induced spending by employees of the project and its suppliers. Total employment earnings associated with operations are in the order of $104 million for all of Michigan. Total output from the abandonment construction expense would be $362 million, for a total value added of some $190 million.

Detailed results (see Appendix Q) show that the corridor counties could account for as many as 1400 of the total 2200 (full- and part-time) jobs, and for as much as $69 million of the total employment earnings.

Table 4-6: Alternative 6b: Full Abandonment of Line 5

Alternative 6b: Abandonment Expenditures Related to Line 5			
Abandonment Expenditures for all of Line 5 – terrestrial plus Straits Crossing			$212 million
Abandonment Expenditures for all of Line 5 – terrestrial in MI plus Straits Crossing			$184 million
Impact Area	Employment (jobs)	Labor Earnings (million $)	Output (million $)
Michigan			
Direct	977	53.2	183.5
Indirect	450	24.1	91.6
Induced	761	26.9	87.0
Total impact	2188	104.3	362.1
Value Added for Michigan: $190 million			
Notes: Economic contribution results derived using BEA RIMS II Multipliers.			

The contribution of this alternative to government revenue is estimated to be $5.0 million through consumer income taxes, sales taxes, and transportation fuel taxes. This estimate is for Michigan as a whole, and is not attributed to counties or Prosperity Regions within the state. The reader is reminded that impacts and revenues from a short-term activity will not necessarily occur in the period of the original investment.

4.3.3 Social Impact Screening

For each alternative, Appendix Q provides socioeconomic analysis for SIA screening; the results of which are summarized in Table Q-6 (see Appendix Q). Under Alternative 6, the SIA screening draws attention to potentially significant land disturbance impacts (infrastructure disruption, tribal land), and temporary housing impacts (population influx in the area of the Straits).

Land disturbance will be minimal because the abandonment approach is *in place*. However, filling pipeline segments at 156 crossings, and decommissioning large pump stations for land reclamation will cause both urban and rural traffic disruptions. Also, in most of the counties of the Upper Peninsula where Line 5 currently passes there exists tribal land. Land disturbance impacts would need to be assessed for tribal concerns.

Construction activities associated with the abandonment of the Line 5 Straits of Mackinac crossing will occur in the Mackinac and Emmet Counties. As with Alternative 4, the influx of construction crews could be problematic given the importance of the tourism sector, and the regular influx of visitors and seasonal workers to this area. Temporary housing impacts need to be assessed. Careful timing of construction activities is normally a feasible mitigation strategy.

The screening conducted in this report is a preliminary assessment and has not included any public processes to define concerns and develop potential mitigation measures.

Mitigation measures for concerns are usually developed closer to more detailed stages of project development.

5 Alternative 2

5.1 General Description

Alternative 2 considers the potential utilization of existing pipeline infrastructure located in Canada, or other U.S., States, as well as elsewhere in Michigan that do not cross the open waters of the Great Lakes, to transport the volume of petroleum products that are currently transported by Enbridge Line 5 from its terminal at Superior, Wisconsin to its terminus in Sarnia, Ontario, and the decommissioning of Line 5.

5.2 Feasibility and Design

For this alternative, the volume forecasts and market outlook for the Enbridge system as well as third party pipelines were used to determine where extra capacity may be available on existing pipelines. The feasibility of this alternative depends largely on the accuracy of the volume forecasts and market outlook for the area.

This analysis takes the simple approach of evaluating capacities and does not take into consideration the challenges of planning the movements of the many different products types (batches) through the various pipelines. This solution will be more complicated than presented in the simplistic analysis below and measures to batch, reverse, or retro-fit the pipeline(s) will need to be determined after available capacities are determined.

In areas where only partial capacity is available, this was evaluated as a combination with a new pipeline build, most likely built along one of the routes discussed in if possible.

5.2.1 Enbridge Pipeline System

The first step in evaluating was evaluating the Enbridge pipeline system. Figure 5-1 is a simplified diagram of the system. For more details on the various lines and capacities refer to Appendix F.

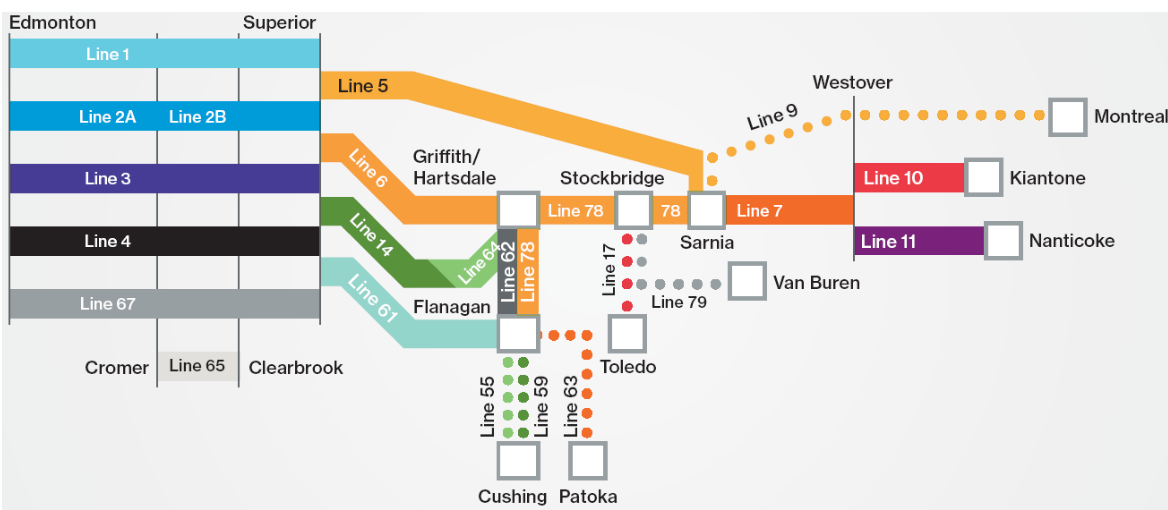


Figure 5-1: Enbridge Pipeline System, Q1 2016

Forecasted volumes for the Enbridge system out to the year 2030 were provided for this analysis. Line 5 is listed with an ultimate capacity of 540,000 bbl/d and is forecasted to stay at capacity for the forecasted future [137].

Enbridge's system to Griffiths/Hartsdale (Chicago) consists of Line 6 and lines 14/64. Line 61 to Flanagan could also be used in combination with Line 62 and a segment of Line 78 to get the product to Griffiths/Hartsdale. However, these pipelines (lines 6, 14/64, and 61) are forecasted to be at maximum capacity within the next three to eight years depending on the line [137].

Enbridge's Line 78 between Griffiths and Sarnia does have some limited spare capacity forecasted for the foreseeable future. This spare capacity is less than 15% of Line 5's total flow between Griffiths and Stockbridge, and less than 1/3rd of Line 5's total flow between Stockbridge and Sarnia. While this spare capacity does not connect to Superior where Line 5 originates, it was evaluated along with new pipeline construction. This pipeline could move the product from Superior to Griffiths and continue alongside Line 78 to Sarnia [137].

The spare capacity from Griffiths to Stockbridge cannot be effectively utilized along with a new pipeline as it is such a small percentage of the Line 5 total flow. A parallel pipeline transporting 85% of the total flow might as well be just as large as it would be for 100% of the flow, due to standard pipe sizes and construction costs.

The spare capacity from Stockbridge to Sarnia is large enough that there could be a reduction in required capacity on a secondary transportation option. However, this transportation distance is only 106 mi. (171 km) in length and would not significantly reduce the cost of a new pipeline alternative.

5.2.2 Existing Non-Enbridge Assets

There are few pipelines which follow Enbridge's routing from Superior to Sarnia, both along Line 5 and south through Chicago, which limits the opportunities to utilize spare capacity. Appendix G details the pipelines in the area and provides routing details.

Additionally, volume forecasts for these pipelines have little or no visibility making it difficult to determine the future availability of any spare capacity. Idle or abandoned pipelines which could be re-purposed would provide the best chance to forecast availability for the significant capacity required for Line 5 volumes.

The following pipelines where evaluated for available capacity.

5.2.2.1 Cochin East Pipeline

The 12-in. Cochin Pipeline originally carried NGL products from Edmonton to Windsor via Chicago. Kinder Morgan reversed the western sections of the line in 2014 to carry diluent from the Chicago area back to Edmonton.

This change provided the possibility of using the Chicago to Windsor segment to carry some of the capacity of Line 5. However, the proposed 2018 Utopia Pipeline project would convert the portion of Cochin East from Metamora Junction, OH to Windsor, ON to transport 50 kbbl/d of ethane and ethane/propane mix, with the capacity for expansion. This would leave only the segment from Chicago to Metamora Junction available to transport Line 5 product. Given that the Cochin Pipeline has only a 12-in.

(305-mm) diameter, and it would only be able to supplement a portion of the Line 5 route, this option was not given further consideration.

5.2.2.2 Guardian Pipeline

The Guardian pipeline is a natural gas pipeline which brings gas from northern Illinois into Wisconsin. This pipeline route could offer the possibility of carrying some of the Line 5 volume part way to Chicago from Superior.

It is owned and operated by ONEOK Partners and currently has expansions underway, indicating that the capacity is under demand. This, combined with the fact that it is a gas pipeline (not oil) and could only possibly carry product for a portion of the route, resulted in it being eliminated from further consideration.

5.2.2.3 Enterprise Products Partnership

The Enterprise Partnership assets are being merged with Sunoco Logistics assets. Sunoco has numerous NGL product lines in the Midwest and NE USA. They also own the crude pipeline between Marysville, MI and the Detroit refinery. Enterprise has numerous pipe assets in the southern states with some lines coming up to Illinois.

As current plans for this pipeline are unknown, and the routing doesn't fully support movement of product from Superior to Sarnia, this option was eliminated from further consideration.

5.2.2.4 TransCanada Mainline

As part of Alternative 1, a Northern Route for a new pipeline was evaluated which parallels much of TransCanada's mainline system. The TransCanada mainline is currently underutilized due to the shale gas revolution which has made imports of gas into Ontario from Ohio and Pennsylvania cheaper than Western Canadian gas.

There is the possibility to repurpose one of the TransCanada's underutilized gas pipelines from North Bay to Barrie, Ontario. This would take approximately 155 mi. (250 km) of new-build out of the Alternative 1.

5.2.2.5 Great Lakes Gas Transmission Mainline

The Great Lakes Gas Transmission mainline carries Western Canadian gas from an interconnection with the TransCanada system at Emerson Manitoba to Sarnia through the Upper Peninsula of Michigan. It roughly parallels Enbridge Line 5 and crosses the Straits. The rebalancing of the natural gas market mentioned above as affecting the TransCanada mainline may also affect the Great Lakes System.

It may be possible to repurpose some, or all, of this pipeline depending upon the natural gas market in North America. This opportunity has been put on low priority as it also involves a mature pipeline crossing of the Straits and is therefore not materially different than the existing Line 5.

5.3 Results Summary and Discussion

From the above analysis, it was determined that there are very limited options to utilize available capacity on existing assets whether they are owned by Enbridge or other parties. The limited visibility on volume forecasts for 3rd party pipelines and the limited number of non-Enbridge pipelines connecting Superior and Sarnia limited the available capacity to two relatively short sections:

- Partial capacity on Enbridge Line 78 from Stockbridge to Sarnia, 106 mi. (171 km) in length
- Potential conversion of TransCanada mainline from North Bay, ON to Barrie, ON, 155 mi. (250 km) in length

Both options would need to supplement either a new build pipeline (Alternative 1) or alternative transportation such as rail (Alternative 3) to accomplish transport of Line 5 products from Superior to Sarnia.

Conversion of existing gas or other product pipelines was not considered in the analysis. This will be an option the market will consider if Line 5 is to be abandoned. This, in concert with other market dynamics, will generally impact and re-align transportation infrastructure in North America.

The most obvious realignment of pipe infrastructure to backfill for Line 5 would be to re-activate the Portland Oil Import Pipeline to Montreal and reverse Line 9 from Montreal to Sarnia, and reverse Line 78 to Stockbridge terminal. Oil can be shipped from Superior to the Gulf Coast by existing pipelines, and then by marine shipments from the Gulf to Portland. Terminal capacities are presently in place for this at Portland and Montreal.

The relatively short length of the available sections, combined with the limited information on availability of the TransCanada line mean this alternative is not significantly different enough from Alternative 1. Therefore, a separate cost analysis was not completed for this alternative.

6 Alternative 1

6.1 General Description

Alternative 1 considers the construction of one or more new pipelines that do not cross the open waters of the Great Lakes to transport the volume of petroleum products that are currently transported by Enbridge Line 5 from its terminal at Superior, Wisconsin to its terminus in Sarnia, Ontario, and the decommissioning of Line 5.

6.2 Feasibility and Design

A significant factor relating to the feasibility of new pipeline construction is tied to the lengthy approval process. Approving new pipelines, especially cross border pipelines, has become more difficult in recent years. However, this is an unavoidable variable for this alternative. Once approved, the feasibility of a new pipeline option will come down to the large capital costs involved.

To evaluate the cost of building a new pipeline to replace Line 5 from Superior to Sarnia three potential route directions were evaluated. Following route selection, preliminary hydraulics and pipeline design were completed and a capital cost estimate was built up from these assumptions. The following sections outline the design assumptions and discuss the costs associated with this alternative.

6.2.1 Pipeline Route

The pipeline routing was performed with the goal of keeping to existing linear energy development corridors wherever possible and to minimize the length and capital costs. All routing was done at the desktop level using Geographic Information System (GIS) data and presents a conceptual level of detail for the routes.

From a high level analysis of the Great Lakes area, three general route directions were evaluated for the new pipeline construction:

- Northern Route through Canada, around the Great Lakes and south to Sarnia
- Central Route following the existing Line 5 into Michigan and crossing the St Marys River into Sault Ste. Marie, Ontario where it would head east to North Bay, Ontario and then south to Sarnia
- Southern Route generally following existing Enbridge assets south to Chicago and east to Marysville and Sarnia

Figure 6-1 is an overview of the northern and southern routes. The following sections discuss the routing for each of these three options and outline the terrain types and specific route considerations.

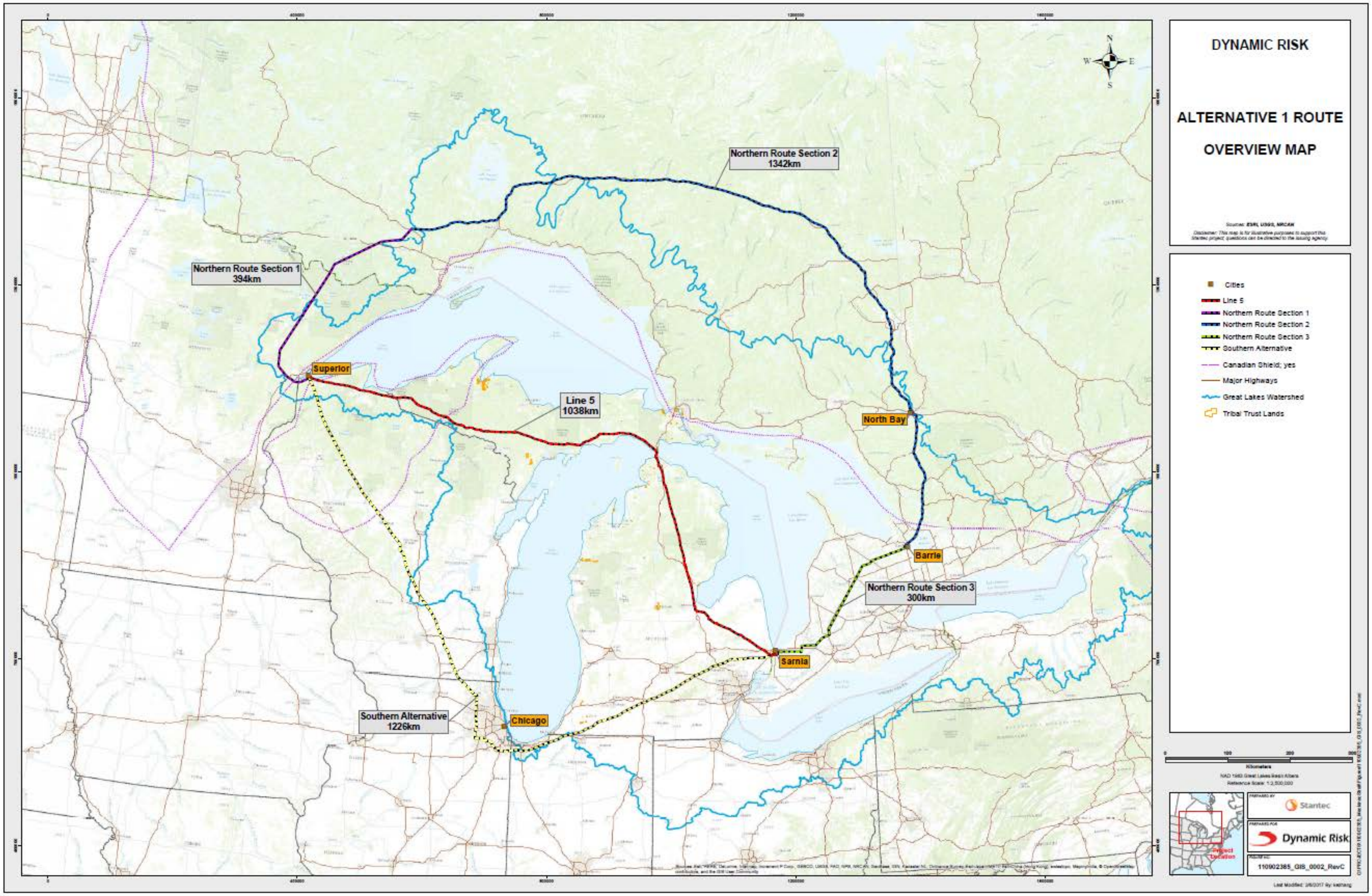


Figure 6-1: Proposed Pipeline Routes

6.2.1.1 Northern Route Option

The TransCanada Pipelines (TCPL) mainline system passes East from Winnipeg through Northern Ontario to North Bay and South from there to the Toronto area. This provides a well-developed ROW for further exploitation for an oil pipeline and provides a basis for much of the routing for this option. TCPL is considering utilizing an existing gas pipeline in this corridor by converting it to oil service giving more credibility to using this route.

The Northern Route is approximately 1,264 mi. (2,035 km) in length. The route traverses a small amount of urban land at Superior and Sarnia (roughly 2% of the route), some agricultural land (roughly 22% of the route), and for most of the route, Precambrian shield (roughly 76% of the route). The route can be described in three main sections as detailed below and shown on the Preliminary Route Overview Map in Figure 6-1.

6.2.1.1.1 Section 1

Starting at Superior, WI, the route follows a path south and west from the existing Enbridge tank farm, bypassing around Duluth and Lake Superior. This short ‘backtrack’ is necessary to bypass Duluth and the western tip of Lake Superior before the route turns northeastward towards Thunder Bay, ON in a new pipeline corridor. The terrain is mostly forested Precambrian shield – one of the most challenging pipeline construction terrains in North America due to the hard rock and deep muskegs found throughout. This segment is approximately 244 mi. (393 km) in length.

6.2.1.1.2 Section 2

Once the route joins up with the TCPL mainline, the route turns eastwards and passes North of Thunder Bay ON. The rugged Precambrian shield terrain lasts until some farmland is encountered around Englehart, ON and then back to Precambrian Shield country, running south to North Bay and on to Barrie, ON. This segment is approximately 834 mi. (1,342 km) in length.

6.2.1.1.3 Section 3

Near Barrie, the pipeline route will cease to parallel the TCPL mainline, turning and running southwestwards. This is in the farmlands of Southern Ontario where it will follow roads and lot boundaries, where possible, until it reaches Sarnia, ON. This segment is approximately 186 mi. (300 km) in length.

The concept of following the TCPL route further South into the Greater Toronto Area (GTA) and then parallel Union Gas West to Sarnia was rejected as those routes were originally chosen in the 1950s/60s and residential development since then has made expansion in these routes very challenging.

6.2.1.2 Northern Route Considerations

The major advantage of this route is that it completely avoids any crossing of the Great Lakes. However, a significant portion of the route is within the Great Lakes watershed. This is not considered a major issue as a number of pipelines already exist within this watershed and a new build pipeline will include state of the art leak prevention and detection technology.

The major drawback of this route is that this is a long route compared to some other alternatives and has a large percentage of Precambrian shield construction. Pipeline construction in the Precambrian Shield is characterized by shallow or surface bedrock – often granitic – requiring expensive excavation techniques such as blasting. These areas have intermittent wetlands which also involve significant and costly mitigation during construction. Being long, it will have both high capital and operating costs in comparison. Also, being mostly within Ontario the relatively higher power costs will also be a factor.

One variation on the Northern Route is to start west of Superior at the Enbridge Clearbrook terminal. This option is 26.5 mi. (42.6 km) longer in length leading to a higher capital cost but the product will not have to flow the extra 189.02 mi. (304.2 km) from Clearbrook to Superior before entering this new pipeline. This 189.0 mi. (261.6 km) of transportation of the product will save on operational costs. However, this is outside the scope of the study.

6.2.1.3 Central Route Option

The Central Route heads east from Superior following the route of the existing Line 5 to a point in Northern Michigan near where Line 5 turns south to cross the Strait of Mackinac. At this point the new pipeline would turn north instead and cross into Ontario near Sault Ste. Marie. This new build would continue Eastbound to North Bay where it would follow the same route as the Northern Route into Sarnia. The total length of this route would be 1,001 mi. (1,611 km).

However, since this route does not eliminate a crossing of the open waters of the Great Lakes but rather simply changes the location, it was rejected as it violates the directive given for this alternative, that apart from the existing Line 5 crossing of the St. Clair River, the new route must not involve a crossing of the open waters of the Great Lakes. Furthermore, alternate crossing methods are being discussed in Alternative 4.

6.2.1.4 Southern Route

The Southern Route is essentially twinning or looping the existing Enbridge system around the South end of Lake Michigan and Chicago. The pipeline would follow Enbridge Line 6 and Line 14/64 routes heading southeast to Chicago. Line 78 is followed northeast from Chicago to Marysville on the West side of St. Clair River where it would cross over into Sarnia.

The Southern Route is approximately 762 mi. (1,226 km) in length. The route traverses a relatively large length of urban areas, especially through the Chicago area (roughly 30% of the route), some agricultural land (roughly 29% of the route), forestry and fishing lands (21%) and Precambrian shield (roughly 20% of the route). The route is shown on the Preliminary Route Overview Map in Figure 6-1. A detailed description of the parallel Enbridge assets in the area can be found in Appendix F.

Of the 762 mi. (1,226 km) of pipeline along this route, approximately 234 mi. (376 km) would be constructed through Michigan.

6.2.1.4.1 Southern Route Considerations

The Southern Route is advantageous in that it follows existing pipelines for most the route. These existing lines set a precedent for new pipeline construction in the area and reduce construction costs in the parallel areas. The route is also much shorter than the Northern Route and includes less Precambrian shield construction.

The main drawback of this route is the congestion that may be encountered through the urban areas. While parallel pipeline corridors will help, urban areas will generally have less construction workspace and more trenchless crossings both of which increase costs.

6.2.2 Pipeline and Facility Design

After routing was completed, preliminary pipeline and facility design was completed for the Southern and the Northern routes.

Throughout this analysis, it is assumed that the replacement pipeline will be a single pipeline with the following characteristics:

- 30-in. outer diameter to match the size of Line 5
- High pressure pipeline with a MOP of 1,440 psi (9,930 kPa)
- Maximum throughput flow of 540,000 bbl/d to match Line 5
- Transported products will match the current make-up of Line 5

Note that the existing Line 5 has a lower MOP. Modern pipeline equipment makes this higher MOP not only technically feasible but common practice as it increases the spacing between pump stations, reducing the number of pump stations required and the capital cost involved.

6.2.2.1 Preliminary Hydraulic Analysis Study

A preliminary hydraulic analysis was completed for both the Northern and Southern routes to determine the required number of pump stations and quantity of power required at each pump station to match the maximum Line 5 throughput of 540,000 bbl/d. Table 6-1 summarizes the results of this analysis.

Table 6-1: Preliminary Hydraulic Analysis Study Results

Results	Northern Route	Southern Route
Total number of stations	17	10
Average distance between stations – mi. (km)	76 (123)	76 (123)
Total power required (kW)	180,232	106,199
Number of stations per country	2 in USA, 15 in Canada	All in USA, 3 in Michigan

The detailed hydraulic analysis can be found in Appendix M.

6.2.2.2 Facilities Design

For this alternative, no additional tanks or other station work is required at the start or end of the pipeline as the new pipeline will simply tie into the existing facilities on both ends of the line regardless of which route is chosen. The required facilities are therefore the pump stations as required by the hydraulic analysis.

Each of these pump stations has been designed as a typical, 30,000 hp pump station. The included items and costs can be found in Appendix H.

6.2.2.3 Pipeline Design

The pipeline design parameters amalgamate the requirements of the American Society of Mechanical Engineers (ASME) and Canadian Standards Association (CSA) to create conservative assumptions which meet the requirements of pipeline design in both countries.

Preliminary wall thickness calculations were completed for the line pipe as well as a heavier wall pipe to be used at crossings and in urban areas. These thicknesses were used to determine the cost of steel on the project. Assumptions used to calculate these wall thicknesses can be found in Appendix C.

Major crossings were then identified based on a Google Earth study of the pipeline routes. These were assumed to be horizontal directional drills, which is typical for major pipeline crossings, and given an average unit length for the purpose of the estimate. For this level of analysis, the differences between the regulatory regimes of Canada and the United States are not significant enough to affect the cost estimate, or design of the crossing methodology.

The Southern Route has a total of 75 major crossings while the Northern Route has 61. Of the 75 crossings on the Southern Route, 17 of these would be located in Michigan with 1 rail, 12 highway, and 4 watercourse crossings.

Finally, three types of fabricated pipeline assemblies were considered in the pipeline design: induction bends, valve sites and pig traps.

Table 6-2: Pipeline Facilities

Assembly Type	Northern Route Quantity	Southern Route Quantity
Induction bends	314	406
Valve assemblies	136	82
Pig traps	18	10

Induction bends are prefabricated pipe bends which were placed at all route changes with angles greater than 24°.

Valve assemblies were placed for isolation of pipeline segments and to limit spill volumes. Valves were placed every 9.3 mi. (15 km) as an average of the regular spacing requirements and the reduced spacing requirements for river crossings and urban areas. For the Southern Route, 25 of the 82 valves would be located in Michigan.

Pig traps facilitate in-line inspection tools which are used as part of the pipeline integrity program. One pig trap will be placed at the beginning of the pipeline, one receiving trap at the end of the pipeline and a receiving/launching pair at every second pump station, or under 186 mi. (300 km), due to the maximum battery life of in-line inspection tools.

For the Southern Route, 25 of the estimated 82 valves and 3 of the estimated 10 traps would be located in Michigan.

6.2.3 Cost Estimate

6.2.3.1 Capital Cost Estimate

The detailed assumptions and costs used to develop the Class 5 cost estimate for this alternative are shown in Appendix H. The estimate has been built up from typical pipeline construction crews, factored pricing for major material items, and percentage based costs for engineering, external consultants and support costs.

Abandonment of the entirety of Line 5 has been included in both the Northern and Southern route estimates. The abandonment costs are based on the Canadian National Energy Board (NEB) Abandonment Cost Estimates document MH-001-2012. Assumptions for Line 5 abandonment can be found in detail in Appendix I.

Table 6-3 lists major cost categories and overall cost for each route.

Table 6-3: Alternative 1 Cost Estimate

Cost Category	Alternative 1 – Northern Route 1,265 mi. (2,036 km)	Alternative 1 – Southern Route 762 mi. (1,226 km)
New materials and transportation subtotal	$978,498,750	$611,000,250
Construction, support services and abandonment subtotal	$2,887,768,500	$1,536,162,000
Engineering and external consultants subtotal	$157,686,750	$90,190,500
Total project cost	$4,023,954,000	$2,237,352,750

Experience with projects of this scale suggest that 5 years will be required to design and construct either the Alternative 1 Northern or Southern Route, with a capital expenditure split of approximately 4% / 6% / 24% / 33% / 33% over those 5 years. This expenditure assumes timely application processes, and includes requirements for detailed route selection as well as pipeline engineering, design, procurement of materials, and on site construction and inspections.

None of the Northern Route will be in the State of Michigan. For the Southern Route, approximately 233 mi. (376 km) of pipeline will be in the State of Michigan. Other major construction items have been split out into Michigan and non-Michigan costs in the previous sections of Alternative 1.

Enbridge’s website lists the capital cost investment for the Line 6B Replacement Project as $2.63 billion. Located in Indiana and Michigan, this was completed in 2014. In comparison, the costs shown in Table 6-3 may seem low when factoring in the length of Line 6B – 285 mi. (459 km).

The above estimated costs do not include Owner’s costs such as land, permitting, and management. These costs can be large depending on the pipeline company. A project with many permitting and application issues will also have substantially higher Owner’s costs. These costs are difficult to determine since publicly available cost breakdowns are often not available.

Contingency was also not included in the above costs and is typically included at a 20% rate.

Finally, pipeline construction and material costs have come down significantly since 2012-2014. Construction costs are 20% lower today than they were in 2014 and steel costs have dropped. Once these items are considered, the total cost of the pipeline will be, in relative terms, within the range of the Line 6B Replacement.

6.2.3.2 Operating Cost Estimate

6.2.3.2.1 Cost Calculations – Common Assumptions

Operating cost estimates for this alternative assume that operations and maintenance (O&M) costs are a percentage of the capital cost. The percentages used are based on liquid pipeline operations experience in mostly rural terrain. The values assume that early O&M costs will be greater in the first several years and gradually settle out over time as the system becomes more efficient, the disturbed land stabilizes and infantile system and equipment failures are experienced and remediated.

The O&M value is a percent of capital expenditures. Note that this is from a top down basis and does not work up from a granular estimate. The estimate assumes a greenfield liquids pipeline project. It includes O&M, ongoing environmental permits and compliance charges, insurance, property taxes, and general and administration costs. These costs do not include fuel or power charges to move the product.

The percentages used for O&M are based on a yearly approximation. O&M figures may vary on a yearly basis as the budgetary cycle of O&M programs may be more functionally and program based than calendar based. For the purposes of this analysis a smoothed O&M expenditure pattern has been assumed:

- Years 1-3 6% of capital expenditure
- Years 4-6 5% of capital expenditure
- Years 7-9 4% of capital expenditure
- Years 10+ 3% of capital expenditure.

The amount of power used to drive the pumps is taken as the installed rating of the pump drivers assuming full throughput for 355 days per year. This implies a 97% utilization rate of the facilities. The volume of throughput is taken from the maximum throughput. The resultant power demand for the pumps is:

- Alternative 1 North has a demand of 180,232 kw
- Alternative 1 South has a demand of 106,199 kw.

Power costs are based on a uniform power supply cost at the plant gate of $0.0768/kwh.

The cost of capital renewal is based on a rate of 1.5% of initial capital expenditure per year. This amount is based on the relative simplicity of the system, the mature technology and the current advanced state of knowledge within the sector. Capital renewal will typically take place with larger programs spaced out over time as replacement analyses warrant. The approach is based on in-house experience with capital renewal programs on various international pipelines. For the analyses in this report, the capital renewal costs are treated as an operating expense.

6.2.3.2.2 Cost Calculations – Northern Route

The capital cost base for the Northern route is $3,812 million (excluding Line 5 abandonment costs). For the Northern pipeline route, the factored O&M costs equate to $229 million/y in year 1 declining to a stable value of $114 million/y by year 10 and onwards. Power costs are assumed to be constant during this period in real terms: $120 million/y. Capital expenditure renewal is $58 million/y. This results in operating costs of $407 million/y upon start-up, with a long-term expected cost of $293 million/y after ten years of operation.

6.2.3.2.3 Cost Calculations – Southern Route

The capital cost base for the Southern route is $2,025 million (excluding Line 5 abandonment costs). For the Southern pipeline route, the factored O&M costs equate to $122 million/y in year 1 declining to a stable value of $61 million/y by year 10 and onwards. Power costs are assumed to be constant during this period in real terms: $70 million/y. Capital expenditure renewal is $31 million/y (excluding a nominal IDC allowance). This results in operating costs of $225 million/y upon start-up, with a long-term expected cost of $165 million/y after ten years of operation.

6.2.3.2.4 Summary

For each alternative, the annual operating cost is estimated to be:

- Northern Route Operating Cost (Year 1) = $407 million/y
- Northern Route Operating Cost (Years 10+) = $293 million/y
- Southern Route Operating Cost (Year 1) = $225 million/y
- Southern Route Operating Cost (Years 10+) = $165 million/y.

Due to the substantial cost advantage of the southern route in both capital and operating costs, the northern route was screened out at this stage and the southern route was selected for continued analysis of market impacts, socioeconomic impacts and risks. The reader will note that, because the northern route does not pass through Michigan, both capital and operating expenditures in Michigan are expected to be zero.

For the purpose of the socioeconomic impact analysis of the Southern Route, this report uses the long-term operating cost (Years 10+) as a potential economic driver within the State of Michigan. For the southern route, this equates to $165 million/y.

6.3 Cost-Effectiveness and Market Impacts

6.3.1 Levelized Costs

Appendix P provides detail on levelized cost assumptions and methods. The levelized costs under the base case discount rate of 6%/y for the two routings are presented in Table 6-4. The cost advantage of the southern route is apparent in the standalone levelized cost, which at a 6%/y discount rate is $2.98/bbl for the northern route and $1.63/bbl for the southern route. The levelized cost reflects both the capital and operating cost, as well as the 5-year construction period before product can be moved.

Table 6-4 also shows the incremental contribution of the Line 5 abandonment. It is assumed that the abandonment occurs just after these alternatives would hypothetically commence production. Abandoning Line 5 before construction starts would still create a 5 year gap during which no infrastructure exists as a replacement: the impacts for such a scenario are identical to those in Alternative 6b over this five year period and market conditions down the road might not necessarily guaranty that such lines would be constructed. For this reason, it is assumed that Line 5 operations continue over the five years and that abandonment of Line 5 is deferred until new facilities are commissioned.

Table 6-4: Cost Comparison of Northern and Southern Pipeline Alternatives

Routing	Northern Route	Southern Route
Capital Costs excluding Line 5 Abandonment	$ 3,812 million	$ 2,025 million
Operating Costs	$ 407 million/y at start-up $ 293 million/y by year 10	$ 225 million/y at start-up $ 165 million/y by year 10
Sub-total Project Levelized Cost	$2.98/bbl	$1.63/bbl
Total Levelized Costs Superior – Sarnia/Marysville area (including Line 5 Abandonment)	$3.05/bbl	$1.70/bbl
Note: Above results are based on 6%/y real discount rate and 5 year construction period. See Appendix R [Cost-Effectiveness Analysis] for further assumptions and results relating to discount rate sensitivity.		

6.2.3 Market Impacts – Southern Pipeline Alternative

Table 6-5 shows that Line 5 abandonment will in due course contribute to system costs under this alternative. Unlike full abandonment as described in Alternative 6, however, this abandonment occurs once the new pipeline is fully operational to transport 540 kbbl/d.

The standalone levelized cost of this alternative is $1.628/bbl.

Table 6-5: Levelized Cost – Alternative 1S

Alternative	Levelized Cost (6%/y) 540 kbbl/d			Levelized Cost (6%/y) 2,600 kbbl/d
	Reference ($/bbl)	Line 5 Abandonment ($/bbl)	Total ($/bbl)	Total ($/bbl))
1S South Pipeline	1.628	0.067	1.695	0.352

Market impact is summarized in Table 6-6. The standalone levelized cost of $1.628/bbl translates to an average impact on the market cost seen by shippers and refiners of $0.352/bbl once abandonment costs are incorporated. The $0.352/bbl increase in shipping costs for Alternative 1S equates to a $0.00986/gal increase (1.0¢/gal).

In addition, however, the market impacts associated with propane supplies to the Upper Peninsula and crude injections at Lewiston would still occur as described in Section 4. The new pipeline routing does not involve service to these locations.

No direct market impacts from this activity would arise for the approximately 5 year period of implementing this investment. There may, however, be other speculative investments that occur anticipating increased capacity in pipeline deliveries. Impacts from such investments have not been investigated in this report.

Table 6-6: Market Impacts – Alternative 1S

Alternative	Levelized Cost r=6%/y	Market Impact System	Market Impact Consumer
1S South Pipeline	1.628 $/bbl	+0.352 $/bbl	+1.0 ¢/gal

6.4 Socioeconomic Impacts of Replacement Facilities

6.4.1 Introduction

In Alternative 1, a new pipeline moves Line 5 products south from Superior, WI, around the bottom of Lake Michigan, through Illinois, clipping the northwest corner of Indiana, and up into Michigan. It enters Michigan in Berrien County, and runs northeast to St. Clair County where it exits Michigan into Ontario. It assumes a right-of-way (ROW) width of 38 yards. It needs 3 pumping stations along its Michigan stretch. It would have four work spreads of about 70 mi. each.

The construction of the new southern pipeline follows the ROW of existing pipelines, which in addition to reducing construction cost also reduces land use impacts because existing linear infrastructure is already in place along the entire route. Most of the pipeline passes through sparsely populated counties with low levels of urban development.

Eleven Michigan counties in Prosperity Regions 6, 7, 8, 9 and 10 would be affected by construction and eventual operation of a new south pipeline. Economic impacts (jobs, income, output) of construction and operation costs are discussed in Section 6.4.2. Other socioeconomic impacts are summarized in Section 6.4.3. All socioeconomic impacts associated with Alternative 1 are discussed in greater detail in Appendix Q.

6.4.2 Construction and Operations Economic Impacts

6.4.2.1 Construction Costs

Economic multipliers (BEA RIMS II) were used to estimate the economic impacts of a new southern pipeline see Table 6-7. As designed, the southern pipeline is approximately 761 mi. (1226 km) long, but only 227 mi. (365 km) of the line would cross Michigan. Consequently, out of the estimated $2,025 million in construction expenditures for this alternative, only $586 million is attributable to the Michigan portion of the new line. Of that amount, construction expenditure on materials and services produced or provided by Michigan contractors is estimated to be $435 million.

The construction expenditure on the Michigan portion of the south pipeline would directly support approximately 3000 (full- and part-time) jobs within the state. Another 5000 jobs would result from indirect spending on materials and services by construction contractors, and induced spending by employees working for any supplier implicated in the construction process. Employment supported by the construction of the south pipeline in Michigan could translate to approximately $369 million in total earnings. Total output from construction expenditure could be $1,308 million, for a total value added of some $396 million.

Detailed results (see Appendix Q) show that as many as 6300 (full- and part-time) jobs could be located in the ROW counties, accounting for as much as $320 million in earnings.

Table 6-7: Alternative 1: South Pipeline Route Construction Impacts

Alternative 5: South Pipeline Route			
Total Estimated Cost of the new Pipeline			$2,025 million
Construction Expenditures Specific to the Michigan Portion of the Pipeline			$586 million
Michigan-sourced Construction Purchases			$435 million
Impact Area	Employment (jobs)	Labor Earnings (million)	Output (million)
Michigan			
Direct	3,118	154.4	585.8
Indirect	2,297	119.5	413.8
Induced	2,695	95.3	308.0
Total contribution	8,110	369.2	1,307.5
Value Added currently contributed to Michigan: $396 million			
Notes: Economic contribution results were derived using BEA RIMS II multipliers.			

The contribution of this alternative to government revenue is estimated to be $17.7 million. Government revenue is based on estimates of consumer income, sales, and transportation taxes. This estimate is for Michigan as a whole, and is not attributed to counties or Prosperity Regions within the state. The reader is reminded that impacts and revenues from a short-term activity will not necessarily occur in the period of the original investment.

6.4.2.2 Operation Expenses

Economic multipliers (BEA RIMS II) were used to estimate the economic impacts of the operation of a new south pipeline (see Table 6-8). When the south pipeline goes into service, its total operation cost would be about $165 million/y. Recall that this represents the long-term operating cost estimate for this alternative. The Michigan portion of the new pipeline's operation cost is estimated to be about $49.5 million/y. The direct employment impact to the state of the operation expense could be 126 (full- and part-time) jobs. The indirect and induced economic impacts could result in another 270 (full- and part-time) jobs.

Total employment earnings from operations could translate to approximately $24 million/y. The total output generated by the southern pipeline operations would be about $80 million/y with value added to the Michigan of economy $43 million/y

Detailed results (see Appendix Q) show that as many as 300 (full- and part-time) direct and indirect jobs could be located in the ROW counties, accounting for as much as $18 million/y in earnings.

Table 6-8: South Pipeline Route Operation Economic Impacts

Alternative 5: South Pipeline Route			
Operation Expense – total for WI, IL, IN, & MI			$165 million/y
Operation Expense for portion of the line in Michigan			$49.5 million/y
Impact Area	Employment (jobs)	Labor Earnings (million $/y)	Output (million $/y)
Michigan			
Direct	126	12.9	44.2
Indirect	98	4.8	15.6
Induced	175	6.2	19.9
Total contribution	399	23.9	79.7
Value Added currently contributed to Michigan: $42.5 million/y			
Notes: Economic contribution results were derived using BEA RIMS II multipliers.			

The contribution of this alternative to government revenue is estimated to be $1.15 million/y through personal income taxes, sales taxes, and transportation fuel taxes. In addition, $5-10 million/y are from pipeline and related facility taxes. This estimate is for Michigan as a whole, and is not attributed to counties or Prosperity Regions within the state.

6.4.3 Social Impact Screening

For each alternative, Appendix Q provides socioeconomic analysis for SIA screening; the results of which are summarized in Table Q-6 (see Appendix Q). Under Alternative 1, the SIA screening for construction of the pipeline draws attention to infrastructure disturbance impacts (traffic circulation). Regarding the eventual operation of the new pipeline, no socioeconomic impacts were flagged other than the economic impact of operations presented above.

Pipeline construction is linear, with work crews and worksites moving along the route as work progresses. Hence construction crew influxes to local communities will be relatively short in duration. Most of the pipeline passes through sparsely populated counties with low levels of urban development. In these areas, impacts of construction activities on local communities may be easily mitigated. However, 23% of the total pipeline length passes through the densely populated urban areas of Macomb and Oakland counties. In these areas, infrastructure disruption impacts may be more significant and require more complex mitigation strategies.

The screening conducted in this report is a preliminary assessment and has not included any public processes to define concerns and develop potential mitigation measures. Mitigation measures for concerns are usually developed closer to more detailed stages of project development.

6.5 Risk Assessment of Pipeline Failure

The risk assessment conducted on this Alternative considers the risk associated only with the operation of new pipeline segments that are required to bypass the existing crossing of the segment of Line 5 that crosses the Straits.

For the purposes of this analysis, risk is defined as a compound measure of the expected frequency of an adverse event (in this case, a loss of containment, or failure within the replacement segment), and the consequences of failure. Because the consequences of failure are in part a function of release magnitude, the frequency of failure is characterized in terms of various magnitudes. This enables risk to be expressed as the frequency of each release magnitude and its associated consequences.

6.5.1 Failure Probability Analysis

The failure likelihood component of the risk expression described above is conveyed quantitatively as the annual probabilities associated with each of a set of representative release magnitudes within the segment of pipeline that would be used to bypass the Straits segment of Line 5.

6.5.1.1 Methodology

For the purposes of this analysis, only general information is available regarding design, alignment and operating conditions of the hypothetical replacement segment. This lack of detail precludes the application of reliability methods, which require detailed design and operating information, or site-specific evaluation of potential geohazards as a means of evaluating probability of failure. For this reason, failure likelihood evaluations were based solely on industry incident data by selecting the incident database in such a way that it reflects, to the greatest degree possible, the infrastructure being proposed.

A comprehensive report on failure statistics by cause for onshore hazardous liquid pipelines is maintained by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) [2]. This database contains pipeline failure statistics for approximately 187,000 mi. (300,947 km) of onshore hazardous liquids pipelines in the US. An accompanying mileage database enables failure frequency estimates derived on the basis of these incident data to be quantified in normalized terms (failures/mi.-y).

While the PHMSA incident database lends itself to sorting and filtering on various fields, the degree to which the mileage database enables filtering is quite limited, and so it is this database that presents limitations with respect to the degree to which industry incident data can be matched to the infrastructure that is the subject of the analysis. Nevertheless, filtering of the incident data and the accompanying mileage database was performed to the extent possible to match the characteristics of the hypothetical 30 in. (762 mm) diameter replacement pipeline.

A review of the PHMSA Hazardous Liquids Incident Database is database was completed for the years 2010 through 2016, inclusive. Filters were applied to this database, as follows:

- Onshore pipeline infrastructure only;
- Pipeline ROW, including valve sites only (excluding pump stations, meter stations tank farms, etc. and associated piping); and,
- Installation date of 1980 or later (this was done to reflect modern material, design and construction practices[28]).

The PHMSA Hazardous Liquids incident database characterizes each release by a qualitative descriptor: 'Rupture', 'Leak', or 'Puncture', and failure frequency estimates were provided in those terms. The General Instructions for completing accident forms provides these definitions:

- Mechanical Puncture

  A puncture of the pipeline, typically by a piece of equipment such as would occur if the pipeline were pierced by directional drilling or a backhoe bucket tooth. Not all excavation-related damage will be a "mechanical puncture".

- Leak

  A failure resulting in an unintentional release of the transported commodity that is often small in size, usually resulting in a low flow release of low volume, although large volume leaks can and do occur on occasion.

- Rupture

  A loss of containment that immediately impairs the operation of the pipeline. Pipeline ruptures often result in a higher flow release of larger volume. The terms "circumferential" and "longitudinal" refer to the general direction or orientation of the rupture relative the pipe's axis. They do not exclusively refer to a failure involving a circumferential weld such as a girth weld, or to a failure involving a longitudinal weld such as a pipe seam.

6.5.1.2 Results

The following numbers of failure events were recorded over the seven year span covered by the incident data from 2010 – 2016, inclusive:

- 112 leaks
- 11 ruptures
- 1 puncture.

[28]This date corresponds to the advent of a number of technologies that have come to characterize *modern* pipelines, including:

- The use of continuous slab casting and thermomechanical controlled processing (TMCP) technology for skelp production.
- High-strength low alloy (HSLA) low-sulfur shape-controlled, high-toughness steels.
- Implementation of quality systems and highly-constrained pipe manufacturing variables.
- Use of highly-constrained mechanized welding systems.
- Use of 100% non-destructive testing of girth welds as common practice.
- Development and use of high-performance corrosion coating systems.
- Implementation of quality management systems during design, construction and operation, piggable designs.

Over the time period evaluated, an average of 64,408 mi. (103,655 km) of pipeline was operating with attributes as defined by the filters described in Section 6.5.1.1. On that basis, the failure frequency rates attributed to all threats are:

- leak: 2.48×10^{-04}/mi.-y
- rupture: 2.44×10^{-05}/ mi.-y
- puncture: 2.22×10^{-06}/ mi.-y

Based on the 753 mi. (1,212 km) length of the hypothetical 30-in. replacement pipeline, the annual probabilities of failure associated with the operation of that replacement segment are:

- leak: 0.187 per year
- rupture: 1.84×10^{-02} per year
- puncture: 1.67×10^{-03} per year
- expected annual probability of any form of loss of containment: 0.203.

6.5.2 Spill Consequence Analysis

6.5.2.1 Release Analysis

The purpose of this analysis is to determine the volume of oil that could be released into the environment in the event of a leak, rupture or puncture in a hypothetical 30-in. pipeline replacement.

6.5.2.1.1 Methodology

As mentioned in Section 6.5.1.1, only general information is available regarding design, alignment and operating conditions of the hypothetical replacement pipeline. The lack of detail on the alignment and the site-specific land use precludes the application of a comprehensive outflow model to determine the volume of the released oil along the pipeline corridor. For this reason, the released volumes were determined by relying on industry incident data derived from the US DOT's PHMSA Hazardous Liquids Transmission Incident Database (2010 to 2016 inclusive), which was filtered (see Section 6.5.2.1.2) to reflect the hypothetical 30-in. pipeline replacement.

For this analysis, an approach consistent with the methodology discussed in Section 6.5.1.1 was employed to evaluate the volume of the oil released associated with each release classification, as characterized below:

- Mechanical Puncture

  A puncture of the pipeline, typically by a piece of equipment, such as would occur if the pipeline were pierced by directional drilling equipment or a backhoe bucket tooth.

- Leak

  A failure resulting in an unintentional release of the transported commodity that is often small in size, usually resulting in a low flow release of low volume, although large volume leaks can and do occur on occasion.

- Rupture

  Loss of containment that immediately impairs the operation of the pipeline. Pipeline ruptures often result in a higher flow release of larger volume.

6.5.2.1.2 Results

Table 6-9 shows the release volumes associated with each release classification. The release volumes are determined based on review of PHMSA incident data from 2010 to 2016 for pipelines with diameters between 24 and 36 in. (see Section 6.5.1.1).

Table 6-9: Oil Release Volume per Release Classification

Release Classification	Median Release Volume (bbl/incident)
Leak	57.45
Rupture	3,784
Puncture	300

6.5.2.2 Oil Spill Analysis

Only releases of oil were considered and analyses are represented in semi-quantitative terms with qualitatively discussed environmental consequences. GIS overlay and extrapolations techniques for Michigan counties and affected States were used to identify higher risk representative spill pathways or receptors. This included the following along the pipeline corridor:

- locations and quantities of river and stream crossings
- locations and quantities of drainage crossings
- location and lengths of transected 'wetland areas'
- location and transected 'protected areas'
- location of the alternative rail route in relation to where drinking water could be a risk
- Location and length of transected urban areas.

With the above identification of oil release exposure pathway characteristics / receptors, project experts qualitatively outlined the potential scale of consequences related to the most exposed environmental receptors.

6.5.2.2.1 Discussion: Behavior of Released Oils

To frame the discussion on possible consequences to identified represented receptors, the following subsection provides an overview of key physiochemical variables that influence an oil spill and an explanation of the acute and chronic impacts associated with them.

When released into the water environment, oils can undergo a series of physical and chemical changes, i.e. spreading, drifting and weathering depending on the type of oil spilled (i.e. their specific gravity, viscosity, volatility, solubility and surface tension), the spill size, the environmental conditions (i.e. hydrodynamics, water quality and climate conditions) and the onset times of the spill.

Table 6-10 describes weathering processes and categorizes into ‘water surface’ and in the ‘water column’ categories.

Table 6-10: Weathering Processes

On the water surface			
Processes	Onset Time	Factors of Influence	Behavior
Spreading	Immediately on spill	Viscosity and surface tension of oil Wind speed Wave and current speeds	Increases the overall surface area of the spill Enhances mass transfer via evaporation, dissolution and later biodegradation.
Evaporation	Within hours or days	Volatility of oil Thickness of slick	Vaporization of lighter or more volatile hydrocarbons where residual oil becomes denser and more viscous It accounts for 75% mass lost from condensates and ultra-light oils, 20-30% from light oils and ≤10% from heavy oils [107]
Photo-Oxidation	Over months or years	Presence of sunlight	Oil reacts with oxygen in the presence of sunlight to form products that are either more water soluble or persistent compounds called tar balls It accounts for <0.1% of mass loss per day [108]
Emulsification	Over months or years	Wind/Wave actions	Formation of mixtures of oil and water droplets either water-in-oil or oil-in-water emulsions which increases the volume and surface area of the spill. Emulsification is less likely to occur in freshwater, even for spills of heavier oils, due to insufficient physical mixing.
In the water column			
Dissolution	Within hours or days	Solubility of oil	Dissolution is the dissolving of oils in the water column. Only 2-5% of oil is loss by dissolution [109] as many soluble components are also volatile which evaporates at a rate of 10 to 1000 times faster than dissolution [110]
Natural Dispersion	Within hours or days	Viscosity of oil Wave and current speeds	Dispersion occurs as oil droplets detach from the slick and become entrained in the water column. Depending on the droplet size, depth and mixing, larger droplets may coalesce and resurface while smaller droplets may remain dispersed in the water column [109] Lighter oils tend to produce smaller oil droplets due to their lower viscosity.
Submergence and Sedimentation	Over months or years	API Gravity of oil	Sedimentation is the submergence or sinking of oil which become entrained in the underlying sediments. This usually occurs for heavier oils with higher density than the water column due to adhesion to sediment particles.
Biodegradation	Over months or years	Biodegradability of oil Nutrient levels	It is the breakdown of oil by naturally occurring microorganisms. Oil degradation is generally faster in well-aerated water column under aerobic conditions.

The above processes, for the most part, are similar for freshwater and marine water, as they pertain to oil properties in terms of chemistry and composition. Ramifications to ecology from an oil spill however are also dependent on the following factors:

- environmental factors affecting the spilled oil and behavior (such as presence of microbial species in oil-impacted water and sediments, temperature, level of dissolved oxygen, etc.)
- their impacts on different aquatic environments (which are dependent on properties of the substrate, riverine morphology, lake size, etc.).
- Spills that occur in stagnant or low-flow condition, especially near the banks of the river and in the hyporheic zone, may behave as a transient storage zone and release oil at slower rate which extend their residence time in the stream.
  - During high-flow condition, bulk oil is likely to enter the riparian zone and become stranded on vegetation or entrained in underlying sediments.
  - Oil spilled in wetlands tend to be adsorbed on vegetation or within fine anaerobic sediments commonly found in wetlands which may significantly reduce their biodegradation rate.
- the importance of the oil type in relation to the environment (e.g. light crude oils for instance are moderately volatile and contain moderate concentrations of highly toxic soluble compounds. They could result in long-term contamination of resources)

Spilled oil can be lethal to many aquatic fauna such as fish, birds and mammals due to the physical effects of smothering (particularly in species that must surface frequently) and damage to fur and feathers affecting thermal insulation and buoyancy. Furthermore, dissolved components of oil and the less soluble components of oil such as PAHs can also cause chronic and sub-lethal effects to these organisms. The level of toxicity varies with different species and their exposure to oil type, environmental conditions and life history and physiology of these species.

6.5.2.2.2 Discussion: Sensitive Aquatic Environments

The Pipeline Alternative would entail transporting high volumes of oils and NGLs over aquatic environments. Calculations indicate that 3,784 bbl of oil could be spilled in environmentally sensitive areas due to rupture events. The volumes for leaks and punctures are 300 bbl and 57 bbl respectively. Table 6-11 provides an overview of the related spill exposure of aquatic environments.

As apparent from Table 6-11, Michigan would experience the lower levels of river, stream and canal crossing then Wisconsin spill; with 8 rivers, 24 streams, 5 drainage canals, but the highest cumulative length wetlands crossed at of 231 mi. Comparatively, Wisconsin would have 29 rivers and 56 streams crossings, and approximately 130 mi. of wetlands traversed. Illinois would have lesser numbers of aquatic environments crossing and is therefore deemed to experience lower levels of risk to aquatic habitats.

Further discussion on the specific risk and potential environmental consequences from the Pipeline Alternative aquatic spills to the State of Michigan are shown (see Figure 6-2) and discussed below.

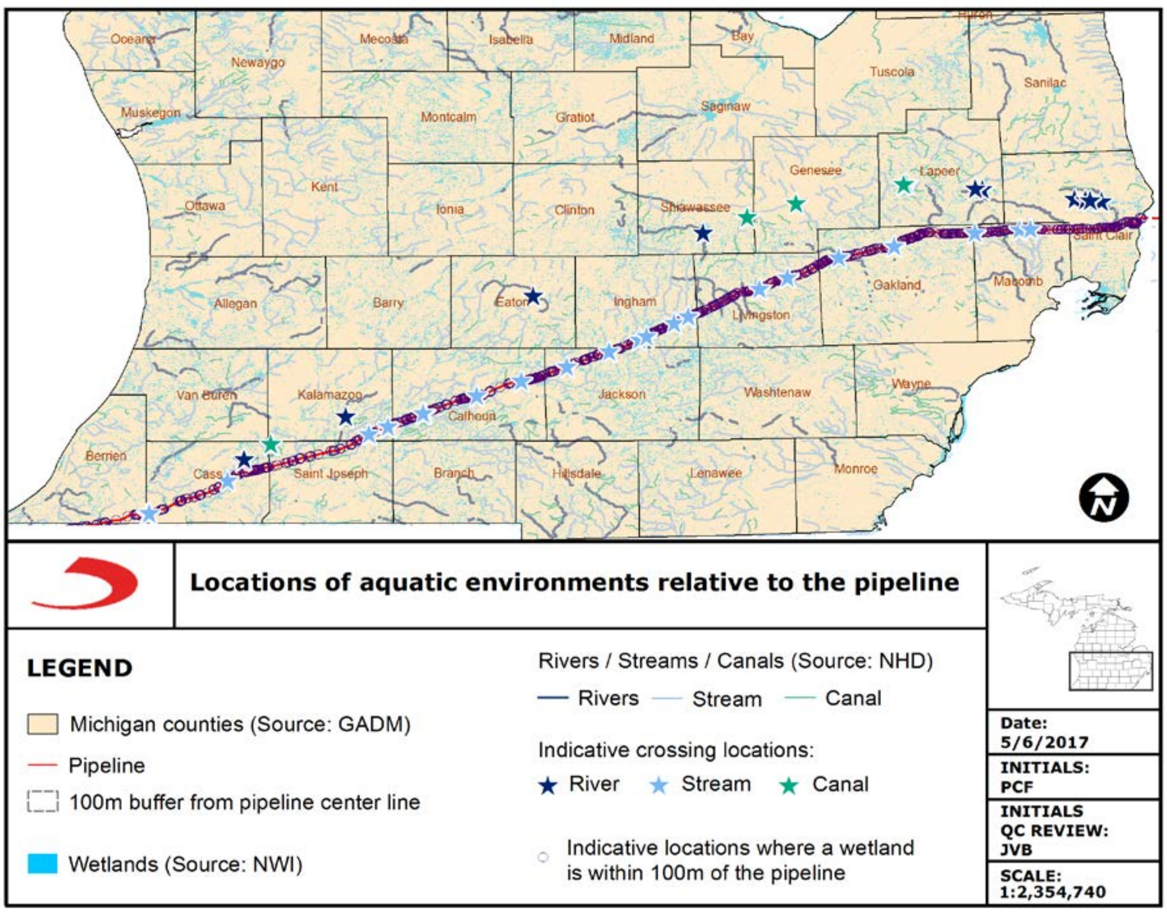


Figure 6-2: Illustration of Pipeline Intersected Aquatic Environments in Michigan

Table 6-11: Overview of Pipeline Intersected Aquatic Environments

State / County		Number of Crossings			Wetland Crossings		Pathway, Receptors Names & Descriptions	
		Rivers	Stream	Canal	Number	Length (mi.)	Rivers	Wetlands
Michigan	Berrien	-	-	-	224	8.86	-	Where applicable the 3 largest wetland types intersected, incl. - Riverine - Freshwater Forested / Shrub Wetland - Freshwater Emergent Wetland
	Calhoun	0	3	1	960	45.99	N/A	
	Cass	0	2	0	862	24.12	N/A	
	Ingham	0	4	0	840	19.42	N/A	
	Jackson	0	4	0	446	17.14	N/A	
	Kalamazoo	0	2	0	170	7.86	N/A	
	Livingston	4	2	0	894	30.97	Red Cedar River, West and Middle Branch Red Cedar Rivers, South Branch Shiawassee River	
	Macomb	1	3	0	446	21.12	North Branch Clinton	
	Oakland	2	2	1	1,184	24.01	South Branch Flint River, Shiawassee River	
	St. Clair	1	2	1	470	11.06	Pine River	
	St. Joseph	0	0	2	258	6.39	N/A	
	Total	8	24	5	6,754	216.94	N/A	
Illinois		3	26	0	854	19.82	Des Plaines River, DuPage River, Fox River	- Riverine - Freshwater Emergent Wetland - Freshwater Pond
Indiana		3	10	7	2,790	64.31	Deep River, East Arm Little Calumet River, Little Kankakee River	- Riverine - Freshwater Forested / Shrub Wetland - Freshwater Emergent Wetland
Wisconsin		29	56	0	5,308	130.60	Many[29] such as the Fox, Namekagon River and Yellow River	- Riverine - Freshwater Forested / Shrub Wetland - Freshwater Emergent Wetland

[29]Amnicon River, Black River, Chippewa River, Crawfish River, East Branch Sturgeon River, East Fork Moose River, Eau Claire River, Fisher River, Flambeau River, Fox River, Jump River, Little Amnicon River, Little Jump River, Little Presque Isle River, Little Thornapple River, Maunesha River, Middle River, Namekagon River, Nemadji River, North Branch Crawfish River, North Fork Eau Claire River, Popple River, Saint Croix River, Slate River, Thornapple River, Totagatic River, Wisconsin River, Yellow River

As evident, the Red Cedar and its Middle Branch and West Branch, Shiawassee and its South Branch, South Branch Flint and North Branch Clinton Rivers in Michigan would all be crossed by the alternative Pipeline route. Significant wetlands traversed by the Pipeline in Michigan were of relatively similar nature as those crossed by the Rail option, i.e. Riverine, Freshwater Forested / Shrub Wetland, and Freshwater Emergent Wetland, and would therefore incur similar consequences from potential spills, which are covered throughout the discussion carried out for the Rail option (i.e., Alternative 3 in Section 7.5.2.2.2).

6.5.2.2.3 Discussion: Lesser Sensitive / Non- Sensitive Receptors

The Pipeline option would also entail transporting higher volumes of oils and NGLs over non-specific aquatic environments; such as various urban areas, agricultural land, industrial areas and protected areas. This includes, but is not limited to, the representative terrestrial receptors, i.e. Protected, HPA Urban, and Drinking Water Resource areas presented in Table 6-12.

As apparent, the Pipeline Alternative would transect or come within 95 yards of Protected Areas[30] 13 time in Michigan; namely in Cass, Livingston, Macomb and Oakland Counties, where 32 mi. of this area would be bisected by the pipeline itself. Wisconsin, however, would experience the highest spill exposure Protected Area crossings at 24 occurrences and 66 mi. of a direct route through several county forests.

In relation to Highly Populated Areas (HPAs), Michigan has the highest number of occurrences, i.e., 4 HPAs at Berrien, Livingston, Oakland and St. Clair Counties, for a total length of 52.9 mi. This is followed by Illinois and Indiana with approximately 173 mi. and 140 mi. of traversed HPAs spread over 2 crossings respectively. There are no HPAs crossed in the state of Wisconsin.

With respect to loss of access to drinking water resources in Michigan, the GIS extrapolation showed that 11 drinking water resource areas, totaling 70.69 mi. in length would be exposed to potential Pipeline oil spill (see Table 6-12 and Figure 6-3).

30 Official Protected Open Spaces - U.S. Geological Survey, Gap Analysis Program (GAP). May 2016. Protected Areas Database of the United States (PAD-US), version 1.4 Combined Feature Class.

Table 6-12: Overview of Pipeline (100 m Buffered) Intersected Non-Environmental Sensitive Areas

State / County		Protected Areas		Urbans Areas (HPAs)		Drinking Water Resources		(Example) Receptors Names
		Number	Length (mi.)	Number	Length (mi.)	Number	Length (mi.)	
Michigan	Berrien	-	-	1	18.26	-	-	HPAs: South Bend
	Calhoun	-	-	-	-	2	20.95	Drink Res.: 115 Truck Shop, Marshall Academy
	Cass	1	23.40	-	-	1	7.35	Prot. Areas: Crane Pond State Game Area Drink Res.: Marlin Village MHP
	Ingham	1	N/A	-	-	-	-	Prot. Areas: Ingham
	Livingston	1	0.13	1	2.86	1	5.43	HPAs: South Lyon, Howell Drink Res.: Daily Press & Argus
	Macomb	4	0.55	-	-	-	-	-
	Oakland	5	7.92	1	4.48	7	36.96	Prot. Areas: Horseshoe Lake State Game Area, Polly Ann Trail HPAs: Detroit Drink Res.: Advanced Auto Trends; Heather Highlands; Long Lake Village Subdivision
	St. Clair	1	N/A	1	27.30	-	-	HPAs: Port Huron
	Total	13	32.00	4	52.90	11	70.69	
Illinois		29	27.33	2	173.47	-		Prot. Areas: Pratts Wayne Woods, Stickney Run Conservation Area, James “Pate” Philip HPAs: Chicago, Round Lake Beach, McHenry, Grayslake
Indiana		5	27.40	2	139.59			Prot. Areas: Hoosier Prairie Nature Preserve, Laura Lake Conservation Easement, Hoosier Prairie – Reichelt Tract HPAs: Chicago, Michigan, LaPorte
Wisconsin		24	66.48	-	-			Prot. Areas: Douglas County Forest, Rusk County Forest, Washburn County Forest

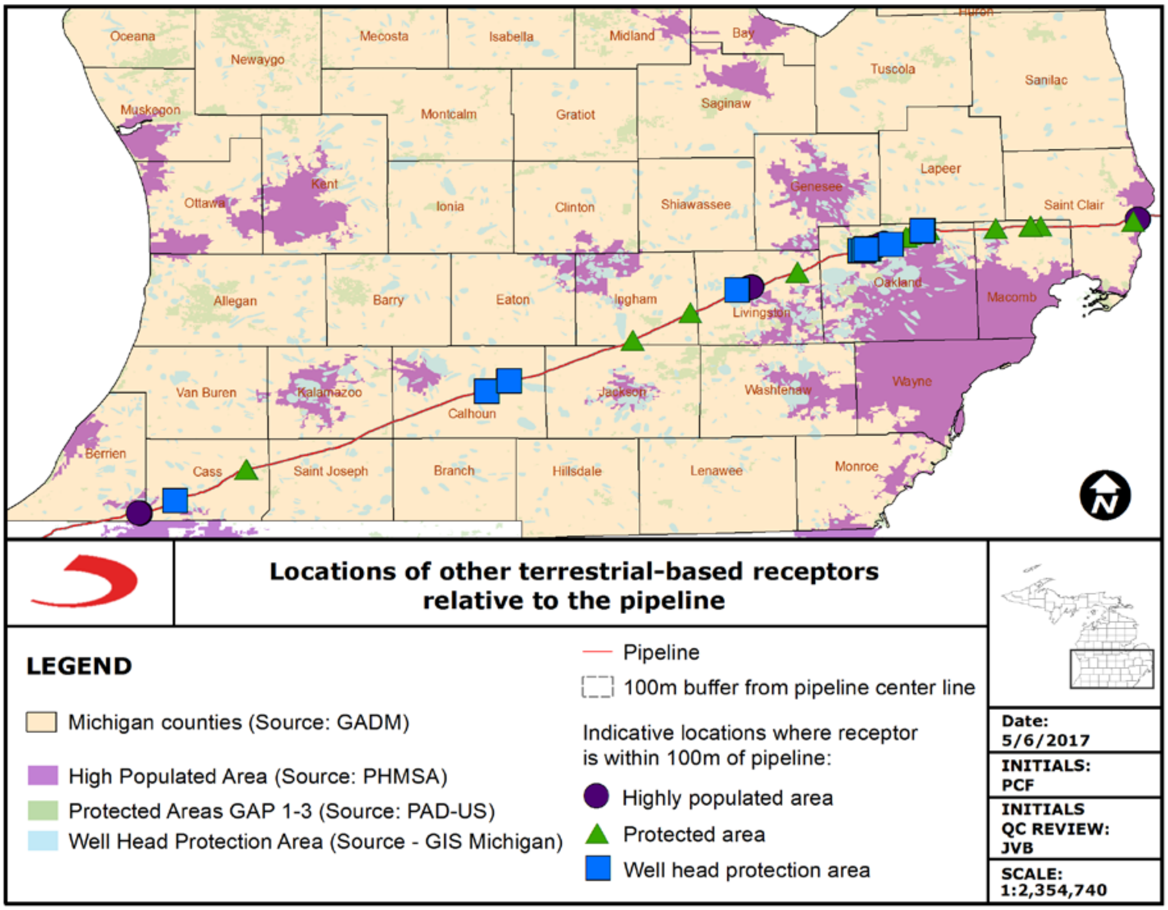


Figure 6-3: Illustration of Pipeline Intersected Terrestrial Environments

6.5.2.3 NGL Release and Dispersion Analysis

As discussed in Section 2.4.2.5, the safety impacts of a spill from Line 5 (or the replacement alternative) is dominated by the NGL releases. The NGL release and dispersion associated with such releases are assessed in the following sections.

6.5.2.3.1 Methodology

The NGL discharge and dispersion analysis was conducted using DNV PHAST v. 7.11. Table 6-13 includes the representative hole sizes and the corresponding release classifications as identified in Section 6.5.2.1.1. The hole sizes were determined based on the recommended representative sizes included in [138, p. 297].

Table 6-13: Release Sizes and Classifications

Release Classification	Hole Diameter
Leak	0.2 in. (5 mm)
Rupture	28.4 in. (721 mm) – pipe ID

Release Classification	Hole Diameter
Puncture	2 in. (50 mm)

6.5.2.3.1.1 NGL Release Modeling

PHAST's "Long Pipeline" model was used to determine the rate at which the NGLs are released to the environment in the event of a pipeline rupture. The average release rate was calculated over the initial five minutes of the release. The five-minute period was selected because of rapid reduction in the initial release rate, which typically occurs in FBR events due to the pressure reduction in a pipeline.

For leak and puncture events, the representative hole diameters are significantly smaller than the pipeline's ID; therefore, it is reasonable to assume a multi-dimensional flow within the pipe once the breach occurs. For this reason, the *Leak* model was utilized to determine the release rates for these events. Furthermore, for releases associated with leak and puncture events, initial discharge rates were used, reflecting the fact that a significant reduction in the release rate is not expected.

The release directions were determined based on the approach recommended in section 2.1.3 of *DNV Consequence Modelling Report* [139]. In accordance with that guidance, for each release size, three release directions were modeled:

1. Vertical release – modeled as vertical release without any modification of normal discharge modeling output (i.e., full discharge velocity).
2. Horizontal release – modeled at angle of 45° upward with reduced velocity to reflect loss of momentum on impact with the crater side.
3. Downward release – modeled as a vertical release with low velocity to reflect loss of momentum on impact with ground beneath.

The release modeling was conducted using a pressure of 1,305 psi (9,000 kPa) as provided in Appendix M and assuming valve spacing of 9.3 mi. (15 km), as defined in Section 6.2.2.3.

6.5.2.3.1.2 NGL Dispersion and Fire Modeling

The safety consequences of an NGL spill on land are primarily due to the thermal radiation which is produced if the release is ignited. Typical flammable events resulting from such a release are identified and defined below [139]:

- Fireball – a spherical fire resulting from the sudden release of pressurized liquid or gas that is immediately ignited.
- Jet fire – immediate ignition of pressurized flammable hydrocarbon releasing continuously from a pipe resulting in an intense and highly directional fire with significant momentum. Crater fire is formed if the jet's momentum is lost.
- Pool fire – fire resulting from ignition of liquid hydrocarbon pool.
- Flash fire – delayed ignition of flammable vapor plume, dispersed in an uncongested area, whose dimensions are determined directly from the dispersion modeling as the distance to the lower flammability cloud.

As discussed previously, the NGLs transported by Line 5 includes lighter hydrocarbon, most of which flashes to a gaseous phase after being discharged from the pipeline. Therefore, pool fires are not considered a significant hazard associated with release of NGLs transported by Line 5.

Of the thermal radiation hazards associated with gaseous products that are heavier than air, flash fires represent the dominant hazard due to the significant distances that a flammable cloud can travel, relative to radiant heat transfer distances. Therefore, in regards to fireball and jet fire events, the hazard extents corresponding to such scenarios tend to be smaller than the impacted area associated with flash fire events. Furthermore, considering the majority of the pipeline route travels through the rural areas (low population density), the probability of an immediate ignition resulting in a fireball or a jet fire is considered low. Blast overpressure, and damage associated with that hazard is only feasible at unusually high levels of congestion that are typically not associated with cross-country transmission pipelines. Furthermore, blast overpressures are not associated with flash fires, and so blast overpressure effects are not considered in quantitative risk assessments where flash fires effects are considered [129, p. 202]. For these reasons, flash fires are assessed as the dominant safety hazard associated with NGLs releases from the hypothetical 30-in. pipeline replacement.

The dispersion of flammable gas was modeled using the UDM within DNV PHAST v. 7.11. Similar to the approach employed in Section 2.4.2.4.1, six representative weather categories were selected for modeling purposes, as outlined in Table 6-14 and Table 6-15.

Table 6-14: Wind and Stability Category [140]

Wind Speed Category	Wind Speed Range mph	Representative Wind Speed[31] mph	Probability of Occurrence	Pasquill Stability Class
Low	≤4.5	4.5	29%	F – Moderately stable
				D – Neutral
Medium	4.5 to 13.4	8.3	59%	B – Moderately unstable
				D – Neutral
				E – Slightly stable
High	≥13.4	16.6	12%	D – Neutral

Table 6-15: Atmospheric Parameters [141] [142]

Parameter	Value	Unit
Average atmospheric temperature	48.7	°F
Relative humidity	70	%
Solar radiation flux (day)	0.5	kW/m^2
Atmospheric pressure (absolute)	1.01	bar

[31]The representative wind speeds are determined using probability weighted average, with the exception of the low wind speed class. 4.5 mph (7.2 km) is typically used to represent low wind speed in dispersion modeling.

6.5.2.3.2 Results

Employing the methodology described in Section 6.5.2.3.1, the NGL release rates and the LFL distances (i.e., potential impact radii) for each combination of release size, release direction, and weather category were determined.

Table 6-16 lists the average release rates and the weighted average LFL distances for each release size.

Table 6-16: Flammable Cloud Distances

Release Classification	Release Size in. (mm)	Average Release Rate lb/s (kg/s)	Weighted Average LFL Distance ft. (m)
Leak	0.2 (5)	2.6 (1.2)	10 (3)
Rupture	28.4 (721) – pipe ID	4,364.4 (1,979.7)	1,545 (471)
Puncture	2 (50 mm)	259.4 (117.7)	216 (66)

6.5.2.4 Health and Safety Consequence

As discussed in Section 6.5.2.3.1.2, the dominant safety hazard associated with an NGL release is the flash fire caused by the ignition of a flammable cloud. An assessment of the ignition probabilities and the impacted population is included in the following sections.

6.5.2.4.1 Methodology

6.5.2.4.1.1 Release Location and Potential Impact

For the purpose of this analysis, it is assumed that all release sizes (i.e., leak, puncture, and rupture) could occur anywhere along the pipeline. Using the potential impact radii identified in Table 6-17, an assessment of the type of land use surrounding the pipeline infrastructure was conducted to establish the type of areas impacted by each release size. The following land use types were considered in the assessment:

- HPA – includes urban areas
- OPA – includes low residential areas
- Others – includes other sensitive and non-classified areas.

HPAs and OPAs are derived from PHMSA information based on the 2010 census and serve as guidance for routing design in the pipeline industry.

Table 6-17 provides the impacted area based on the release classification.

Table 6-17: Impacted Area based on Release Classification

Release Classification	Impacted Area mi^2 (km^2)
	Overall

	HPA	OPA	Others
Leak	0.376 (0.974)	0.140 (0.363)	2.340 (6.061)
Rupture	60.780 (157.419)	21.272 (55.094)	110.208 (285.437)
Puncture	8.414 (21.792)	2.982 (7.723)	15.443 (39.997)

Table 6-18 provides the proportion of the area over which the spill impacts populated areas.

Table 6-18: Proportion of Area over which Spill Impacts Populated Areas

Release Classification	Proportion of Area over which Spill Impacts HCA		
	Overall		
	HPA	OPA	Others
Leak	13.39%	4.98%	82.20%
Rupture	13.79%	4.83%	82.20%
Puncture	13.62%	4.83%	82.20%

6.5.2.4.1.2 Density

The population density for each area was determined using the guidelines provided in [127, p. 13]. Table 6-19 lists land type and population density.

Table 6-19: Land Type and Population Density

Land Type	Population Density people/mi^2
High Population Area (HPA)	3,176
Other Population Area (OPA)	527
Other Sensitive Area and Non Classified Areas (Others)	15.2

6.5.2.4.1.3 Ignition Probability

The methodology used for calculating the ignition probabilities was consistent with the approach described in Section 2.4.2.5.1.2. Figure 6-4 demonstrates the correlations used to determine ignition probabilities.

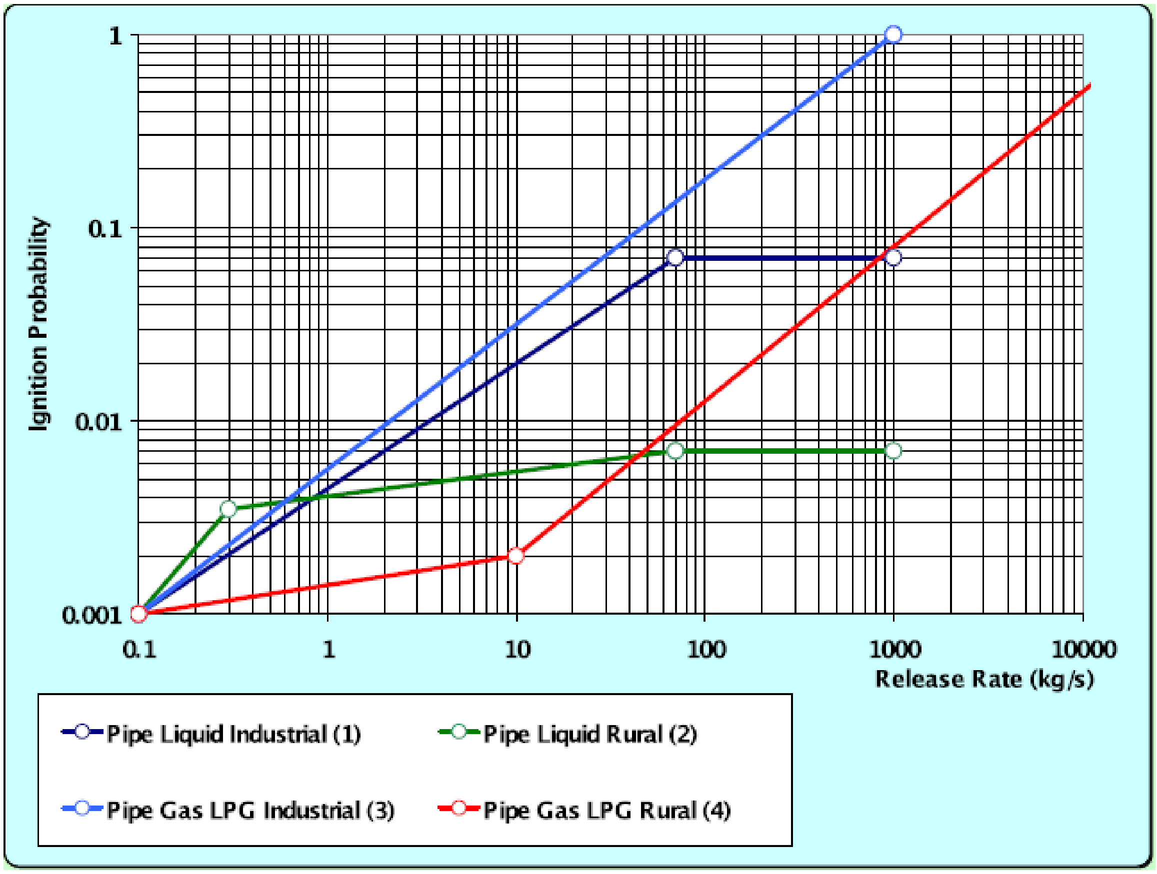


Figure 6-4: Release Rates vs. Ignition Probabilities [143]

Using the release rates identified in Table 6-16, Correlation 3 was used to determine the ignition probabilities for releases occurring in HPAs, where the possibility of a flammable cloud meeting an ignition source is higher. Similarly, Correlation 4 was employed to evaluate the ignition probabilities for releases occurring in areas identified as OPAs and Others, where ignition probabilities are expected to be lower. Table 6-20 summarizes the resulting ignition probabilities for each land use type.

Table 6-20: Ignition Probabilities based on Land Use

Release Classification	Average Release Rate lb/s (kg/s)	Ignition Probabilities based on Land Use[32]		
		HPA	OPA	Others
Leak	2.6 (1.2)	0.01	0.01	0.01
Rupture	4,364.4 (1,979.7)	1	0.15	0.15
Puncture	259.4 (117.7)	0.3	0.02	0.02

[32]The minimum ignition probability is taken as 1% as recommended by [211].

6.5.2.4.1.4 Hazard Vulnerability

As discussed in Section 2.4.2.5.1.3, consistent with industry best practice, the general approach to modeling the vulnerability of individuals to flash fire events is to assume that those located within the flame envelope of a flash fire have a 100% probability of fatality and that individuals outside are unaffected. Table 6-21 lists flash fire vulnerability criteria.

Table 6-21: Flash Fire Vulnerability Criteria

Location	Probability of Fatality
Within lower flammability limit cloud	1
Outside lower flammability limit cloud	0

6.5.2.4.2 Results

The average number of individuals impacted by the potential flash fire resulting from a failure of the hypothetical 30-in. replacement pipeline was calculated for each release size, as shown in Table 6-22.

Table 6-22: Average number of Impacted Individuals per Event

Release Classification	Average Number of Individuals Impacted within HPA per Event	Average Number of Individuals Impacted within OPA per Event	Average Number of Individuals Impacted within Other Areas per Event
Leak	0	0	0
Rupture	855	142	0
Puncture	17	3	4

6.5.2.5 Economic Consequence

The economic analysis of the spill costs involves the direct estimation of cleanup costs and a factored estimate for eventual damages. In simplest terms:

Total Spill Costs = Total Response & Clean-up Costs + Total Damage Costs

The response and cleanup costs are a function of factors such as spill remoteness, spill size, amount of onshore oiling, type of cleanup technique used, time of year, and oil density and chemistry. Cleanup costs are also affected by the nature of onshore areas that are impacted by the spill. The damage estimate reflects potential longer term social and environmental costs associated with damages to natural resources, restoration of environmental functions, and impacts on both commercial and subsistence resource harvesting.

The spill cost modeling provides linear and non-linear functions for a number of the factors associated with the spill. The model is based on historical experience with spills in the U.S. and with global maritime spills. The model is particularly appropriate for the estimation of hypothetical spills, as it is based on statistical findings related to global spills over the past three decades. The model excludes fines and penalties associated with a spill event.

6.5.2.5.1 Methodology

As further described in Appendix R, the project interpreted land-use along the southern pipeline corridor to assess the economic consequence of spills within high consequence areas (HCA).

The definition of an HCA used in this study includes four classes: Highly Populated Areas (HPAs), Other Populated Areas (OPAs), Environmentally Sensitive Areas (ESAs) and Other Sensitive Areas (OSAs).

HPAs and OPAs are derived from PHMSA information based on the 2010 census and serve as guidance for routing design in the pipeline industry. Populated areas are regarded as an HCA because a large class of social damages that show as compensated damages in spill cost data are tied directly or indirectly to environmental resources: water contamination, soil contamination, damaged belongings, and lost access to resources or recreational opportunities are all more acute in populated areas.

ESAs are based on all categories included within the U.S. National Wetlands Inventory, including navigable waters. Wetlands are an appropriate basis for estimating damages because wet areas generally have the highest value in natural resource damage assessments (NRDA) used in oil spill damage claims.

OSAs are defined within this study as 10% of the above classes and is intended to reflect a broad range of otherwise high consequence areas that may not be captured by the HPA, OPA, and ESA designations. For example, the GIS interpretation also identified potentially culturally important heritage sites that are proximate to the corridors, but are represented by a single point rather than a linear feature or aerial feature. Also, most routings of any infrastructure potential include cultural or traditional uses that are identified only when detailed route planning is commenced and affected groups are consulted. A contingency for OSA is thus used to reflect these potential areas.

For all spills, a weighted average of spill costs was calculated based on the proportion of the corridor intersecting an HCA; spill costs in an HCA are generally higher than those not in an HCA.

Intersects of HCA by a pipeline were calculated using two methods. Direct intersects are the linear distance (in miles) of the pipeline with a land-use type classified as an HCA. Indirect intersects reflect a broader area-based measure (in square miles) defined by a corridor that extends outwards from the centerline of the infrastructure. pipelines that cross a river would count just the crossing length in their “direct HCA proportion”; those following alongside a river on one bank might follow a river for miles, yet show zero direct intersect. The indirect measure is therefore regarded as appropriate for most spill modeling with potentially significant consequences.

This study applies an indirect approach for moderately large oil spills (>1000 bbl). The oil spill model, however, also makes one exception to this approach for smaller spills. Some proportion of all spills typically stays within the bounds of operating company property or an already modified right-of-way. For small spills, therefore, the use of indirect GIS interpretive methods tends to overstate spill risk because the HCA designation would include the right-of-way as HCA even though it is not associated with a high consequence. The spill model used in this study therefore uses the direct intersect measure for pipeline spills under 1,000 bbl; these are regarded as providing a more accurate representation of potential impacts of a hypothetical release.

6.5.2.5.2 Results

The resultant interpretations of HCA proportions for the Alternative 1 pipeline oil spills are:

- rupture (3,784 bbl) = 35.34% in HCA
- puncture (300 bbl) = 30.61% in HCA
- leak (57 bbl) = 30.61% in HCA.

These proportions are for the entire routes from Superior to the US-Canada border at the St. Clair River. Readers are reminded that the environmental consequences are described for these corridors as a whole; the consequences inside any given state are not estimated.

6.5.2.6 Environmental Consequence

As outlined in Section 1.9.5, for the purposes of characterizing and comparing the environmental risk between the various alternatives considered in this report, by convention, the environmental component of economic consequence has been adopted to represent environmental consequence. This measure of environmental consequence is based on a monetization of the damages, which in principle encompass the following impacts, provided that these impacts can be directly associated with a spill event:

- restoration costs of the natural environment
- a broad range of environmental damages normally included within a natural resource damage assessment (NRDA), including air, water and soil impacts.
- net income foregone in the sustainable harvest of a commercial resource
- net value foregone in the sustainable harvest of a subsistence resource, including fisheries.

The quantified elements of spill cost reflect an expected value of damages contingent upon the occurrence of an initial spill event.

6.5.2.6.1 Methodology

As further described in Appendix R, the project interpreted land-use along the southern pipeline corridor to assess the economic consequence of spills within HCAs.

The definition of an HCA used in this study includes four classes: HPAs, OPAs, ESAs and OSAs.

HPAs and OPAs are derived from PHMSA information based on the 2010 census and serve as guidance for routing design in the pipeline industry. Populated areas are regarded as HCAs because a large class of social damages that show as compensated damages in spill cost data are tied directly or indirectly to environmental resources: water contamination, soil contamination, damaged belongings, and lost access to resources or recreational opportunities are all more acute in populated areas.

ESAs are based on all categories included within the U.S. National Wetlands Inventory, including navigable waters. Wetlands are an appropriate basis for estimating damages because wet areas generally have the highest value in NRDAs used in oil spill damage claims.

OSAs are defined within this study as 10% of the above classes and are intended to reflect a broad range of otherwise HCAs that may not be captured by the HPA, OPA, and ESA designations. For example, the GIS interpretation also identified potentially culturally important heritage sites that are proximate to the corridors, but are represented by a single point rather than a linear feature or aerial feature. Also, most routings of any infrastructure potential include cultural or traditional uses that are identified only when detailed route planning is commenced and affected groups are consulted. A contingency for OSA is thus used to reflect these potential areas.

For all spills, a weighted average of spill costs was calculated based on the proportion of the corridor intersecting an HCA; spill costs in an HCA are generally higher than those not in an HCA.

Intersects of HCA by a pipeline were calculated using two methods. Direct intersects are the linear distance (in miles) of the pipeline with a land-use type classified as an HCA. Indirect intersects reflect a broader area-based measure (in square miles) defined by a corridor that extends outwards from the centerline of the infrastructure. Pipelines that cross a river would count just the crossing length in their *direct HCA proportion*; those following alongside a river on one bank might follow a river for miles, yet show zero direct intersect. The indirect measure is therefore regarded as appropriate for most spill modeling with potentially significant consequences.

This study applies an indirect approach for moderately large oil spills (>1,000 bbl). The oil spill model, however, also makes one exception to this approach for smaller spills. Some proportion of all spills typically stays within the bounds of operating company property or an already modified ROW. For small spills, therefore, the use of indirect GIS interpretive methods tends to overstate spill risk because the HCA designation would include the ROW as an HCA even though it is not associated with a high consequence. The spill model used in this study therefore uses the direct intersect measure for pipeline spills under 1,000 bbl; these are regarded as providing a more accurate representation of potential impacts of a hypothetical release.

6.5.2.6.2 Results

The resultant interpretations of HCA proportions for the Alternative 1 pipeline oil spills are:

- rupture (3,784 bbl) = 35.34% in HCA
- puncture (300 bbl) = 30.61% in HCA
- leak (57 bbl) = 30.61% in HCA.

These proportions are for the entire routes from Superior to the US-Canada border at the St. Clair River. Readers are reminded that the environmental consequences are described for these corridors as a whole; the consequences inside any given state are not estimated.

6.5.3 Risk Calculation

6.5.3.1 Health and Safety Risk

In risk analysis, Health and Safety risk is conventionally expressed as the annual probability of death of a person, resulting from a hazardous event [123, p. 112]. The hazardous event associated with the calculation of health and safety risk for Alternative 1 is a pipeline failure; specifically, as outlined in Section 6.5.2.4, it is a pipeline failure that precipitates an ignited release of NGLs.

6.5.3.1.1 Methodology

The probabilities associated with pipeline failure for three separate release sizes were determined in Section 6.5.1. Health and Safety Risk ($R_{H\&S}$, fatalities/y) was determined in accordance with Equation 6-1.

$$R_{H\&S} = F_{NGL} \times \begin{bmatrix} \left(P_L \times P_{ign,L,HPA} \times F_{HPA} \times I_{L,HPA}\right) + \left(P_R \times P_{ign,R,HPA} \times F_{HPA} \times I_{R,HPA}\right) + \left(P_P \times P_{ign,P,HPA} \times F_{HPA} \times I_{P,HPA}\right) + \\ \left(P_L \times P_{ign,L,OPA} \times F_{OPA} \times I_{L,OPA}\right) + \left(P_R \times P_{ign,R,OPA} \times F_{OPA} \times I_{R,OPA}\right) + \left(P_P \times P_{ign,P,OPA} \times F_{OPA} \times I_{P,PPA}\right) + \\ \left(P_L \times P_{ign,L,Other} \times F_{Other} \times I_{L,Other}\right) + \left(P_R \times P_{ign,R,Other} \times F_{Other} \times I_{R,Other}\right) + \left(P_P \times P_{ign,P,Other} \times F_{Other} \times I_{P,Other}\right) \end{bmatrix}$$

Equation 6-1: Calculation of Health and Safety Risk

Where:

F_{NGL} = Fraction of the time NGLs are assumed to be transported by the pipeline (= 1/6)

P_L = Annual leak probability (see Section 6.5.1.2)

P_R = Annual rupture probability (see Section 6.5.1.2)

P_p = Annual puncture probability (see Section 6.5.1.2)

$P_{ign,L,HPA}$ / $P_{ign,L,OPA}$ / $P_{ign,L,Other}$ = Probability of ignition associated with a leak occurring in HPAs / OPAs / Other areas (see Section 6.5.2.4.1.3)

$P_{ign,R,HPA}$ / $P_{ign,R,OPA}$ / $P_{ign,R,Other}$ = Probability of ignition associated with a rupture occurring in HPAs / OPAs / Other areas (see Section 6.5.2.4.1.3)

$P_{ign,P,HPA}$ / $P_{ign,P,OPA}$ / $P_{ign,P,Other}$ = Probability of ignition associated with a puncture occurring in HPAs / OPAs / Other areas (see Section 6.5.2.4.1.3)

F_{HPA} = Fraction of area over which releases would impact HPAs (see Section 6.5.2.4.1.1)

F_{OPA} = Fraction of area over which releases would impact OPAs (see Section 6.5.2.4.1.1)

F_{Other} = Fraction of area which releases would impact areas other than HPAs and OPAs (see Section 6.5.2.4.1.1)

I_L = Number of impacted individuals from a leak event (see Section 6.5.2.4.2)

I_R = Number of impacted individuals from a rupture event (see Section 6.5.2.4.2)

I_p = Number of impacted individuals from a puncture event (see Section 6.5.2.4.2)

6.5.3.1.2 Results

From Equation 6-1, the Health and Safety Risk associated with the hypothetical replacement pipeline was determined to be 4.86 x 10^{-04}/mi.-y, which is equal to 3.66x10^{-01}/y for the entire pipeline.

6.5.3.2 Economic Risk

6.5.3.2.1 Methodology

The probabilities associated with three separate failure mechanisms – leak, rupture and puncture were determined in Section 6.5.1.2.

Economic Risk (R_{Econ}, \$/y) was determined in accordance with Equation 6-2.

$$R_{Econ} = F_{Oil} \times \begin{bmatrix} \left(P_L \times F_{HCA,L} \times \$_{L,HCA}\right) + \left(P_L \times \left(1 - F_{HCA,L}\right) \times \$_{L,Non\text{-}HCA}\right) + \\ \left(P_R \times F_{HCA,R} \times \$_{R,HCA}\right) + \left(P_R \times \left(1 - F_{HCA,R}\right) \times \$_{R,Non\text{-}HCA}\right) + \\ \left(P_P \times F_{HCA,P} \times \$_{P,HCA}\right) + \left(P_P \times \left(1 - F_{HCA,P}\right) \times \$_{P,Non\text{-}HCA}\right) \end{bmatrix}$$

Equation 6-2: Calculation of Economic Risk

Where:

F_{Oil}	=	Fraction of the time Line 5 is assumed to transport Oil (= 5/6)
P_L	=	Annual leak probability (= 0.187 per Section 6.5.1.2)
P_R	=	Annual rupture probability (= 1.84x10^{-02} per Section 6.5.1.2)
P_P	=	Annual rupture probability (= 1.67x10^{-03} per Section 6.5.1.2)
$F_{HCA,L}$	=	Fraction of right-of-way over which leaks impact HCAs (= 0.3061 per Section 6.5.2.5.2)
$F_{HCA,R}$	=	Fraction of right-of-way over which ruptures impact HCAs (= 0.3534 per Section 6.5.2.5.2)
$F_{HCA,P}$	=	Fraction of right-of-way over which punctures impact HCAs (= 0.3061 per Section 6.5.2.5.2)
$\$_{L,HCA}$	=	Economic consequences associated with a leak in an HCA (= \$4,880,000 per Appendix R)
$\$_{L,Non\text{-}HCA}$	=	Economic consequences associated with a leak in a Non-HCA (= \$3,150,000 per Appendix R)
$\$_{R,HCA}$	=	Economic consequences associated with a rupture in an HCA (= \$112,450,000 per Appendix R)
$\$_{R,Non\text{-}HCA}$	=	Economic consequences associated with a rupture in a Non-HCA (= \$72,660,000 per Appendix R)
$\$_{P,HCA}$	=	Economic consequences associated with a puncture in an HCA (= \$15,340,000 per Appendix R)
$\$_{P,Non\text{-}HCA}$	=	Economic consequences associated with a puncture in a Non-HCA (= \$9,910,000 per Appendix R)

6.5.3.2.2 Results

From Equation 6-2, the Economic Risk associated with Alternative 1 was determined to be $1,919,000/y.

6.5.3.3 Environmental Risk

6.5.3.3.1 Methodology

The probabilities associated with three separate failure mechanisms – leak, rupture and puncture were determined in Section 6.5.1.2.

Environmental Risk (R_{Env}, $/y) was determined in accordance with Equation 6-3.

$$R_{Env} = F_{Oil} \times \begin{bmatrix} \left(P_L \times F_{HCA,L} \times \$_{L,HCA}\right) + \left(P_L \times \left(1 - F_{HCA,L}\right) \times \$_{L,Non-HCA}\right) + \\ \left(P_R \times F_{HCA,R} \times \$_{R,HCA}\right) + \left(P_R \times \left(1 - F_{HCA,R}\right) \times \$_{R,Non-HCA}\right) + \\ \left(P_P \times F_{HCA,P} \times \$_{P,HCA}\right) + \left(P_P \times \left(1 - F_{HCA,P}\right) \times \$_{P,Non-HCA}\right) \end{bmatrix}$$

Equation 6-3: Calculation of Environmental Risk

Where:

F_{Oil}	=	Fraction of the time Line 5 is assumed to transport oil (= 5/6)
P_L	=	Annual leak probability (= 0.187 per Section 6.5.1.2)
P_R	=	Annual rupture probability (= 1.84x10-02 per Section 6.5.1.2)
P_P	=	Annual rupture probability (= 1.67x10-03 per Section 6.5.1.2)
$F_{HCA,L}$	=	Fraction of right-of-way over which leaks impact HCAs (= 0.3061 per Section 6.5.2.6.2)
$F_{HCA,R}$	=	Fraction of right-of-way over which ruptures impact HCAs (= 0.3534 per Section 6.5.2.6.2)
$F_{HCA,P}$	=	Fraction of right-of-way over which punctures impact HCAs (= 0.3061 per Section 6.5.2.6.2)
$\$_{L,HCA}$	=	Monetized environmental consequences associated with a leak in an HCA (= $0.33 million per Appendix R)
$\$_{L,Non-HCA}$	=	Monetized environmental consequences associated with a leak in a Non-HCA (= $0.21 million per Appendix R)
$\$_{R,HCA}$	=	Monetized environmental consequences associated with a rupture in an HCA (= $67.47 million per Appendix R)
$\$_{R,Non-HCA}$	=	Monetized environmental consequences associated with a rupture in a Non-HCA (= $43.60 million per Appendix R)
$\$_{P,HCA}$	=	Monetized environmental consequences associated with a puncture in an HCA (= $4.21 million per Appendix R)
$\$_{P,Non-HCA}$	=	Monetized environmental consequences associated with a puncture in a Non-HCA (= $2.72 million per Appendix R)

6.5.3.3.2 Results

From Equation 6-3, the Environmental Risk associated with Alternative 1 was determined to be $841,000/y.

7 Alternative 3

7.1 General Description

Alternative 3 considers the potential utilization of alternative transportation methods to transport the volume of petroleum products that are currently transported by Enbridge Line 5 from its terminal at Superior, Wisconsin to its terminus in Sarnia, Ontario, and the decommissioning of Line 5:

1. rail
2. tanker truck
3. oil tankers and barges
4. others.

7.2 Feasibility and Design

7.2.1 Feasibility Analysis of Alternative Transportation Methods

Forecasted volumes for the Enbridge system out to the year 2030 were provided for this analysis. Line 5 is listed with an ultimate capacity of 540,000 bbl/d (barrels per day) and is forecasted to stay at capacity for the forecasted future. This is a relatively large volume to transport by alternative methods and the products transported include both crude oil and NGLs which complicates the transportation and delivery operations.

Pipeline transportation is relatively reliable in that it is not affected by weather or traffic, and many scheduled maintenance tasks can be accomplished without fully shutting down the system. The risk of reduced reliability of other transportation options can be mitigated through redundancy of loading facilities, buffer storage volumes, and a larger than required transportation fleet. This added complexity needs to be considered when evaluating non-pipeline transportation options.

There are three options considered as an alternative to pipeline transportation of the crude oil and NGLs currently moved by Line 5: tanker truck, tanker ship or barge, and rail

7.2.1.1 Tanker Truck

Truck tank trailers have a capacity of approximately 40 m^3 (248 bbl). To handle the Line 5 volumes would require 2,150 trucks per day on average, or an average of 90 trucks leaving the terminal every hour, 24 hours per day.

The journey from Superior, WI to Sarnia, ON by road is about 830 mi. (1,336 km) through Chicago and 710 mi. (1,143 km) through the Upper Peninsula and across the Mackinac Bridge. Assuming the bridge route is only used for the return trip when the truck is empty, and at an average road speed of 50 mph the round-trip driving time is 30 hours which would increase to 34 hours with 2 hours for rest and contingency in each direction.

Using this number, approximately 3,200 trucks would be required to maintain the flow of product. This fleet would cost approximately $1.2 billion with a large renewal cost every 7 years on the tractor and 15 years on the trailers. This is already an extremely large cost without including the cost of the significant facilities required to load and unload 90 trucks per hour.

This rate of added vehicles will put significant strain on the existing infrastructure including wear and tear on public roadways. The probability of accidents associated with such heavy vehicle traffic makes it likely that spills will happen.

The risk factors associated with this option, and the large capital cost, make it non-viable, and therefore no further analysis was conducted for truck transportation.

7.2.1.2 Oil Tankers and Barges

Tanker transportation of crude oil and NGLs from Superior to Sarnia would have to pass through the locks on the St. Marys River at Sault Ste. Marie. The Soo Locks are aging and in need of substantial investment to bring them back to reliable operation for this additional traffic. Should a problem arise or a restriction be placed on these locks the feasibility of this option is severely limited.

Additionally, the Soo Locks between Lake Superior and Lake Huron are closed for repairs from January 15th to March 25th, or two and a half months, each year. To accommodate this situation, volumes would need to be transported by another means or storage capacity would be required in the Superior and Sarnia areas to handle the large buffer volume required. To secure annual throughput in the system equivalent to 540,000 bbl/d, this 70-day shutdown would require 37.8 Mbbl of storage at both the origin on Lake Superior and the terminus near Sarnia (for a total of 75 Mbbl of storage). In addition, the total fleet size would need to be capable of transporting 670,000 bbl/d for the remaining 295 days of the year to fill the storage back up for the next closure.

At a preliminary level, the cost of this storage can be estimated by using 133 tanks, each with a capacity of 570,000 bbl, which cost approximately $15 million each or $2 billion total. The cost of the fleet of barges can be estimated by using 16, 337,000 bbl articulated tank barges at an approximate cost of $140 million each or $2.3 billion total. This cost of $4.3 billion is before any contingency is added, the difficulties of finding enough land for the tanks is considered, or the loading and unloading facilities costs are calculated. The cost of constructing this volume of storage and maintaining a fleet this size is considered an order of magnitude higher than other options and therefore transport by barge or ship is not considered feasible.

7.2.1.3 Rail

Rail is used to transport oil across North America in large volumes, although the volume has come down in recent years due to the reduction in crude oil price spreads and the construction of additional pipelines.

Railcars carrying refined crude oil have a capacity of approximately 650 bbl and cars carrying NGLs have a capacity of approximately 800 bbl. Accommodating Line 5’s capacity of 450,000 bbl/d of crude oil, and 90,000 bbl/d of NGL would require approximately 800 rail cars per day on average. Considering unit trains comprised of 100 cars, this option would require 8 unit trains per day.

Weather and other potential interruptions that may impact a large number of trains would need to be considered. A buffer storage volume of product would need to be available and the fleet of railcars would need to be large enough to catch up within a set period of time.

While there are a large number of rail cars required daily, and there are supply risks which need to be mitigated, this is considered the most practical and cost-effective of the Alternative 3 transportation options.

7.2.2 Alternative Transportation Method Design – Rail

For transport of Line 5 volumes by rail, a new trans-loading facility complete with storage terminal will be required near the existing Enbridge Terminal at Superior, WI. A location 5 mi. (8 km) south of the terminal has been identified as the railcar loading point. This location provides access to existing Enbridge infrastructure which would allow for a transfer through a new 5-mi. (8-km) pipeline connection to a new set of storage tanks, NGL spheres, and associated equipment to be constructed.

From Superior, the railcars will head to Sarnia, ON, where they would be offloaded at another new trans-loading facility complete with storage, 5 mi. (8 km) east of the existing Enbridge Sarnia Terminal. This new set of storage tanks, NGL spheres, and associated equipment would allow transfer through a new 5 mi. (8 km) pipeline connection to the existing tankage. This location will also provide access to existing Enbridge infrastructure which allows transfer to the existing tankage.

As the basis of this study, some main points were held as desirable when evaluating potential options:

- Travel time between origin and destination should be as short as possible to reduce costs.

  This was done to minimize the size of the railcar fleet that would be needed to maintain production. Since the acquisition and maintenance of the fleet represent ongoing costs that would need to be added to the product, our goal was to keep these cost a low as possible.

- Preference is given to routes that will use a single carrier.

  While there are options that would allow transport between origin and destination utilizing multiple carriers, this would be in contravention of the point above. Hand-offs between carriers takes time and would result in increased cost of transport and additional travel time. Canadian National Railway (CN) is the only rail carrier that provides service in the full transport corridor; as such CN is the preferred carrier for this study. While interchanges with Canadian Pacific Railway (CP) are available, in the end another interchange back to CN would be required to complete the journey.

- The proposed route cannot have restrictions that would prevent or impede the proposed operation.

  To minimize the number of railcars needed to move the product it is essential to ensure that all the cars are as full as possible. A route imposing weight restrictions or abnormally slow train speeds would reduce the efficiency of the operation and thus add cost.

The first step was to understand how the trans-loading facility would operate so that we could understand the demands it would place on the rail carrier. This review is covered in the next section.

7.2.2.1 Trans-Loading Operations Summary

The batch-products to be moved by rail are crude oil and NGL. Two different cars are required; one for crude oil, and one for the NGLs which require higher pressure to maintain a liquid state. Two factors limit the capacity of rail cars: weight and volume. In this case, with crude weighing 850 kg/m^3, the maximum capacity of a crude oil car is limited by the 286,000 lb. gross weight of the car. This translates to a maximum volume capacity of 646 bbl per car. For NGLs, with a lesser density of 535 kg/m^3, the volume of 802 bbl limits the car capacity.

Assuming that NGLs are delivered at a relatively consistent daily flow of 90,000 bbl/d, or 16.7%, the pipeline is currently moving the equivalent of approximately 810 railcars of product per day with 697 of crude oil and 113 of NGLs. CN is the rail service provider at both the loading and unloading points in this option and CN operations limit the length of this commodity in a unit train to 100 railcars per train. If the trains leave on a schedule, this means that 9-100 railcar unit trains would need to be loaded and shipped each day from the proposed Superior, WI facility while the same number of trains would need to be offloaded each day at the proposed Sarnia facility.

The trans-loading of the nine trains per day will need to be staggered throughout a 24-h. cycle, resulting in a train leaving the trans-loading facility approximately every 2.5 hours. This staggering is needed to coordinate with CN and maintain fluidity on their network. Releasing multiple trains at once would likely create congestion problems within the CN network as well as staffing issues as the trains are re-crewed along the route. Spreading the release of the trains over the day will provide more flexibility to the operation and make any minor delays more manageable.

Additionally, the trans-loading facilities will need to include additional capacity to make-up volume in the case of an outage on the rail system. Based on experience, it is expected that an outage would normally be cleared within three days. For this analysis, it is assumed that the required recovery time to re-supply this contingency storage after an outage will be a maximum of 10 days.

If the outage is expected to last longer than onsite storage would allow, alternate routes could be utilized or plans to shut down the supply pipeline could be made.

Previous experience with these types of facilities indicates that limiting trans-loading operations to a 12-hour window allows for an efficient use of the trans-loading equipment by accommodating two trains a day with the same equipment. Utilizing this arrangement will require the trans-loading facilities to have a minimum of three racks (each able to load one train on each side) to facilitate the trans-loading of the trains.

With the proposed three rack arrangement, six trains per 12-hour shift can be loaded providing a total of 12 trains/day at maximum capacity. The required capacity for normal operations is nine trains/day therefore the additional three trains/day would allow for recovery from a 3-day outage in 9 days. Additionally, only 810 cars per day are actually full on a regular schedule, so there is an allowance for a quicker recovery from an outage if required.

Each rack will be equipped with 50 dual loading arms, for a total of 300 arms, consisting of 250 crude loading arms and 50 NGL loading arms. This split is to account for the 16.7% of Line 5 flow that is NGLs and assumes that NGLs are delivered at a relatively consistent percentage of daily flow. While this may not exactly match the batching process implemented on Line 5, it is an acceptable approximation for this analysis as exact batching schedules are unknown. To optimize the operation, the racks will be set-up with equipment to service two tracks each; one on either side. This arrangement allows for the minimum amount of infrastructure needed to complete the trans-loading of six trains within the 12-hour window.

The additional racks provide redundancy/capacity to the operation and allow for planned maintenance without impacting the volume of product being handled. This additional capacity would also be instrumental to any recovery effort if rail operations are disrupted.

The trains will be loaded or unloaded 50 cars at a time then progressed through the rack. These trans-loading facilities will require six main loading/unloading tracks, each approximately 12,000-ft. (3,658-m) long to accommodate the 100 car trains powered by two engines.

7.2.2.2 Routes

Three possible routes were identified from Superior, WI to Sarnia, ON:

1. Central Route - Across the Upper Michigan Peninsula, crossing at Sault Ste. Marie
2. Northern Route - North of the Great Lakes
3. Southern Route - South of the Great Lakes

These routes are described in more detail in the sections below. An overview map of these three routes is shown in Figure 7-1 and in Appendix L.

For all routes, the addition of the volume of trains will need to be validated with CN to determine if the service metrics can be met and maintained over the long term. Aside from the volume of traffic to be added to the route daily there is an impact to CN staffing levels along the route which CN would need to provide input on.

Discussions with the CN Marketing Team would provide insights to the plausibility of adding this volume of trains to their network as well as provide more accurate pricing estimates for moving the product. These discussions were not conducted for this initial route assessment.

Figure 7-1: Rail Routes Overview Map

7.2.2.2.1 Central Route

The Central Route across the Upper Peninsula would require passing through Sault Ste. Marie. The bridge over the St Marys River at this location is currently weight restricted to 263,000 lb. (119,295 kg) railcars and would not be suitable for the weight of the equipment being proposed in this study. To reduce the cars to this allowable weight would add an additional train to each cycle. Reducing the efficiency of the trains and adding more equipment to the system runs contrary to our primary considerations; therefore, this route is not considered viable for this study.

7.2.2.2.2 Northern Route

The Northern Route, north of the Great Lakes, requires the trains to travel northwest from Superior WI to Winnipeg, MB where they will then travel east to Toronto, ON and then south to Sarnia, ON. At approximately 1,750 mi. (2,816 km) this is the longest of the three options. However, it does avoid passing through Chicago and the tunnel at Sarnia; both of which are bottlenecks in the CN network.

With an estimated trip time of 64.5 hours one way, and 12 hours each for loading and unloading, this route has a total round trip time of 154 hours, or 6.25 days. This route will require a minimum car fleet of approximately 52 trainsets or 5,200 railcars. This does not include additional cars to accommodate maintenance and repair or additional cars that may be needed in the event of a recovery effort after a rail service outage. The recommended number of additional cars needed for maintenance and service can vary depending on how and where the service is provided; these figures can range from 5%-10% of the fleet size. For this case a 5% addition to the fleet for maintenance rotation increases the total number of railcars required to 5,460.

7.2.2.2.3 Southern Route

The Southern Route, south of the Great Lakes, requires the trains to travel south from Superior, WI to Chicago, IL then east through Indiana and up through Michigan to arrive in Sarnia, ON. At approximately 800 mi. (1,287 km) this is the shortest route that stays with one rail carrier without restrictions.

While this is the shortest route, it does require that the trains pass through or around Chicago and use CN's border crossing at Sarnia. Chicago is a hub for rail travel and is the one place in North America that all the Class 1 railways provide service. This can lead to congestion due to the volume of trains that pass through or are interchanged here. The border crossing at Sarnia is a tunnel under the St. Clair River which represents a potential bottleneck for trains using this track since only so many trains a day can make it through the tunnel. In both cases CN has invested in streamlining these parts of their operation but delays can still occur. It should be noted at this point that the option to offload in Marysville, MI, on the west side of the river crossing, was also considered and is further discussed below.

It should be noted that there is also a border crossing at Detroit, MI into Windsor, ON. This border crossing not only would increase the transit length, but would have the same potential for congestion as the Marysville to Sarnia connection, and thus was ignored for the routing selection.

With an expected trip time of 36 hours one way, 12 hours each for loading and unloading, this route has a total round trip time of 96 hours, or 4 days. This route will require a car fleet of approximately 32 trainsets or 3,200 railcars. This does not include additional cars to accommodate maintenance and repair or additional cars that may be needed in the event of a recovery effort after a rail service outage. Adding 5% additional cars for maintenance rotation increases the total number of railcars required to 3,360.

7.2.2.3 Destination Selection

Sarnia was the original rail termination in mind for this study. However, as the possible routes for the trains were investigated, the border crossing into Canada was identified as a potential bottleneck. To address this, Marysville was identified as a possible alternate destination on the US side of the border. At this location, the products could be offloaded and re-injected into Line 5 for on-going transport to Sarnia.

Destinations along Line 5 further north-west within Michigan were not considered as there are no CN lines in this area and therefore a transfer to another carrier would be required.

7.2.2.3.1 Sarnia, ON

The Sarnia site has existing Enbridge facilities that could be used to place the products back into the existing pipeline infrastructure. Potential land for the rail trans-loading facility was identified east of the existing Enbridge site along the CN ROW. Investigation to determine the feasibility of purchasing the lands will need to be conducted but the area is not heavily developed by either commercial or residential interests.

The leg of existing Line 5 between Sarnia and Marysville may need to be kept active to maintain product flow to the refineries in Michigan and Ohio. The flow rate in this segment is substantially lower than the design flow rate of Line 5, and liquid drop-out may be a concern.

7.2.2.3.2 Marysville, MI

Marysville was chosen as an alternate destination to avoid the crossing of the US/Canadian border and use of the St. Clair River tunnel. While this new destination has a very small effect on the total distance travelled on the Southern route, the elimination of the border crossing is a critical element since it removes a potential bottleneck from the route making it more reliable. This potential increase in reliability is offset by the additional cost of infrastructure and the availability of land in the proposed area.

The trans-loading facility is best situated near the junction between the CN tracks and Line 5 as this will reduce the length of a connector pipeline needed between the facility and Line 5. However, the lands in this area are currently developed with numerous homes built along the local roadways. The Marysville location would also require the construction of infrastructure that is currently available in Sarnia, adding cost to the development of this site.

Further investigation into the public opinion towards locating a trans-load facility in the Marysville area would need to be done to determine if this could be a viable option. Due to the additional cost and current land use in the area it was not considered further for this analysis.

7.2.2.4 Facilities and Pipeline Design

In addition to the trans-loading arms and tracks discussed previously, pipeline links, pumping facilities, and storage tanks are required at both trans-loading facilities to support the transfer of products to and from the existing Sarnia and Superior Terminals.

Products transported through Line 5 are batched and can be separated into two broad categories for the purpose of facility design: crude oil and NGL. The approximate percentage of flow which is NGL is listed as 1/6 or 16.6%, and the remaining 83.4% is crude oil. Due to the batching process, and percentage of flow, it is possible that during a typical 3-day outage all flow may be crude oil. There is also a lesser chance that the majority of the flow may be NGL.

At the Superior Terminal, existing Enbridge facilities, and new pumping facilities will be used to transfer the product to two new pipelines, 24-in. diameter and 30-in. diameter, to transfer the NGLs and crude oil to the new tankage at the trans-loading facility. The 24-in. diameter pipeline is provided to transport the NGLs separately from the crude oil as separate storage and trans-loading arms are required for this type of product. These pipelines will be 5 mi. (8 km) in length.

The same length and size of pipelines will be required at the unloading facility to transfer the products to the Sarnia Terminal. The pumping capacity at each facility is also identical and includes separate pumps for each product type.

The crude oil storage facilities at Superior have been sized to accommodate 3 days of maximum capacity flow through from Line 5 to maintain pipeline operation. At 540 kbbl/d of throughput, a minimum of 1,620 kbbl of total storage is required considering the typical 3-day outage.

As described above, NGL may be batched through the system and there is a small chance that a large volume of NGL is received during an outage. Due to the small chance of this occurring and the relatively large cost of NGL storage, only a small volume of NGL storage has been included to allow a buffer for the trans-loading facilities. If a batch of NGL were scheduled to be received during a rail outage, the pipeline upstream of Superior would require a temporary outage. Early notification of rail outages to shippers and scheduling can be used to mitigate this risk.

Superior storage facilities include:

- 5 x 350 kbbl storage tanks
- 2 x 50 kbbl NGL spheres.

At Sarnia, less crude oil storage has been included than at Superior. Enbridge, refineries, and now the proposed rail facility will all have storage to some extent. This storage along with early notification of rail outages should mitigate any risk of the refineries running out of product. Sarnia storage facilities include:

- 2 x 350 kbbl storage tanks
- 2 x 50 kbbl NGL spheres.

7.2.3 Cost Estimate

7.2.3.1 Capital Cost Estimate

The capital cost required for the base railcar trans-loading facilities remain the same for each of the routes reviewed. This makes the fleet size the next major factor in comparing the costs of the Northern and Southern routes. With the Southern Route being shorter it will require the least number of trainsets to keep it fluid; making it the more cost effective option of the routes considered.

The detailed assumptions and costs used to develop the Class 5 cost estimate for this alternative are shown in Appendix H. The pipeline and facilities estimate has been built up from typical construction crews, factored pricing for major material items, and percentage based costs for engineering, external consultants and support costs.

Abandonment of the entirety of Line 5 has been included in this estimate. The abandonment costs are based on the Canadian National Energy Board (NEB) Abandonment Cost Estimates document MH-001-2012. Assumptions for Line 5 abandonment can be found in detail in Appendix I.

Table 7-1 lists major cost categories and overall cost.

Table 7-1: Alternative 3 Cost Estimate

Cost Category	Alternative 3 (Rail Southern Route)
New materials and transportation subtotal	$460,404,750
Construction, support services and abandonment subtotal	$601,388,250
Engineering and external consultants subtotal	$58,092,750
Total project cost	$1,119,885,750

Experience with projects of this scale suggest that the design and construction of Alternative 3 Southern Route facilities will require 3 years to complete, with a capital expenditure split of approximately 10% / 45% / 45% over those 3 years. This expenditure assumes timely application processes and negotiations with CN or equivalent rail provide. The requirements for detailed route selection, pipeline and facility engineering, design, procurement of materials, and on site construction and inspections are also included.

The rail terminals, the short pipelines, and all storage facilities are located outside of the State of Michigan.

7.2.3.2 Operating Cost Estimate

7.2.3.2.1 Cost Calculations – Common Assumptions

The rail operations cost analysis is divided into two main elements: the rail element and the storage and pipeline elements. The rail element is also divided into transport and loading functions. It was assumed that the terminal storage and pipeline facilities, rail car loading, and rail transport would be three separate entities. The pipelines and storage would be owned and operated by a pipeline company, the rail loading / unloading by a terminal entity, and the rail transport by a rail company. It is assumed that each company has a real return on equity of 10%/y; this is consistent with lease rate assumptions and reflects private sector returns.

Rail transport costs were determined using the American Association of Railways (AAR) Generic Rate 2015 of (US) 3.952 cents per T-mi. This rate was reduced by 25% to account for unit train transport.

Car capacity was estimated at 645 bbl/car for light crudes, which equates to a capacity of 28,433 gal. (129,259 L) per car. Average specific gravity of crude was estimated at 0.850 or an API gravity of 35.

Car capacity was estimated at 802 bbl/car for NGLs, which equates to a capacity of 33,700 gal. (153,203 L) per car. Average specific gravity of NGL was estimated at 0.535 or an API gravity of 133.

Rail car lease costs were determined using a normalized blended rate considering the typical sizes of crude and pressurized cars, the mix of fluids transported, and a forecast of future rates based on historical averages. The lease costs were estimated to be $1,260 per month for light crude oil cars, and $1,575 per month for NGL cars. This was normalized to equal $1,304 per month based on a seven-year lease based for the 86:14 NGL car: crude car split in required rail cars. This split at full capacity was also used to calculate the normalized weight of cars at 93.02 T (84.39 t).

Terminal costs for loading and unloading were based on widely reported average costs of between $1.50 and $1.75/bbl. Due to the size of this operation the low limit of $1.50/bbl was used. Of this $0.25/bbl is a capital return element on the loading and unloading equipment.

A toll for tankage receipt charge based on a 60,000 bbl batch, which is approximately the size of a unit train, was used. The Enbridge receipt tankage tolls RT No 16-3 are $0.0232/bbl ($0.146/m^3).

For the Northern Route of 1,750 mi. (2,816 km), a cycle time of 130 h for the rail transport and 12 h each for loading and unloading was used. For the Southern Route of 800 mi. (1,287 km), a cycle time of 72 h for the rail transport and again 12 h each for loading and unloading is used. Refer to Table 7-1 for details.

Table 7-2: Rail Route Inputs

Input	Northern Route	Southern Route
Length, mi. (km)	1,750 (2,816)	800 (1,287)
Cycle time (h)	130	72
Loading time (h)	12	12
Unloading time (h)	12	12

7.2.3.2.2 Cost Calculations – Northern Route

For the Northern rail route, the costs equate to $7.47/bbl for rail transport, $3.40/bbl for tank car lease loading and unloading, and $0.023/bbl for tank receipt tolls for a total of $10.89/bbl. To avoid double counting of capital charges associated with the terminal capital costs, this is reduced by $0.50/bbl to provide a net cost of the Northern rail route attributable to operations. The resultant net cost of $10.39/bbl results in operating costs of $2,050 million/y.

Refer to Table 7-3 for details.

Table 7-3: Per Bbl Transport Costs – Northern Route

	US Cents (per T-mi.)	Normalized Tons (per Car)	Mi. (km)	Cost (per Car)	Unit Train ($/bbl)
AAR Rail Transport Costs	2.964	93.02	1,750 (2,816)	$4,824.87	7.47
			Cycle days	Monthly lease	
Tank Car Lease Costs Unit Train			6.42	$1,304	0.4017
Terminal Origin (loading), of which ~$0.25/bbl for capital recovery.					~ 1.50

	US Cents (per T-mi.)	Normalized Tons (per Car)	Mi. (km)	Cost (per Car)	Unit Train ($/bbl)
Terminal Destination (unloading), of which ~$0.25/bbl for capital recovery.					~ 1.50
Toll for receipt tankage					0.0232
Total cost per bbl unit train					$10.89
Amount in capital cost (terminal origin and destination)					($0.50)
Total cost per bbl unit train excluding Capital expenditure					$10.39
Total annual operating expenses (540 kbbl/d)					$2,050 million/y

7.2.3.2.3 Cost Calculations – Southern Route

For the Southern rail route the costs equate to $3.41/bbl for rail transport, $3.25/bbl for tank car lease loading and unloading and $0.023/bbl for tank receipt tolls for a total of $6.69/bbl. To avoid double counting of capital charges associated with the terminal capital costs, this is reduced by $0.50/bbl to provide a net cost of the Southern rail route attributable to operations. The resultant net cost of $6.19/bbl results in operating costs of $1,220 million/y. Refer to Table 7-4 for details

Table 7-4: Per Bbl Transport Costs – Southern Route

	US Cents (per T-mi.)	Normalized Tons (per Car)	Mi. (km)	Cost (per Car)	Unit Train ($/bbl)
AAR Rail Transport Costs	2.964	93.02	800 (1,287 km)	$2,205.65	3.41
			Cycle days	Monthly lease	
Tank car lease costs unit train			4.5	$1,304	0.2504
Terminal origin (loading), of which ~$0.25/bbl for capital recovery.					~1.50
Terminal destination (unloading), of which ~$0.25/bbl for capital recovery.					~1.50
Toll for receipt tankage					0.0232
Total cost per bbl unit train using amortized capital					$6.69
Amount in capital cost (terminal origin and destination)					($0.50)
Total cost per bbl Unit Train excluding Capital expenditure					$6.19
Total annual operating expenses (540 kbbl/d)					$1,220 million/y

7.2.3.2.4 Summary

For each alternative, the annual operating cost is estimated to be:

- Northern Route Operating Cost = $2,050 million/y
- Southern Route Operating Cost = $1,220 million/y.

Due to the substantial cost advantage of the southern route in both capital and operating costs, the northern route was screened out at this stage and the southern route was selected for continued analysis of impacts and risks.

7.3 Cost-Effectiveness and Market Impacts

7.3.1 Levelized Costs

Levelized cost methods and calculations are provided in Appendix R – Cost Effectiveness Analysis and are summarized in Table 7-5. The calculation shows that Line 5 abandonment will also in due course contribute to system costs under this alternative. Unlike full abandonment as described in Alternative 6, this abandonment occurs once the rail system is fully operational to transport 540 kbbl/d. This implies that although there may be apportionment required on the pipeline system, the rail deliveries would provide a supply source at a marginal cost equivalent to a non-apportioned pipeline system.

The standalone levelized cost of this alternative is $6.492 /bbl.

Table 7-5: Levelized Cost – Alternative 3S

	Levelized Cost (6%/y) 540 kbbl/d			Levelized Cost (6%/y) 2,600 kbbl/d
Alternative	Reference ($/bbl)	Line 5 Abandonment ($/bbl)	Total ($/bbl)	Total ($/bbl))
3S South Rail	6.492	0.067	6.559	1.362

7.3.2 Market Impacts – Rail

Market impact is summarized in Table 7-6. The standalone levelized cost of $6.492 /bbl translates to an average impact on the market cost seen by shippers and refiners of $1.362 $/bbl once abandonment costs are incorporated. The $1.362/bbl increase in shipping costs for Alternative 3S equates to a $0.0382/gal increase (3.8¢/gal).

In addition, however, the market impacts associated with propane supplies to the Upper Peninsula and crude injections at Lewiston would still occur as described in Section 4. The rail routing does not involve service to these locations.

No direct market impacts from this activity would arise for the approximately 3 year period of implementing this investment. There may, however, be other speculative investments that might occur anticipating an increased availability of rail deliveries. Such additional impacts have not been investigated in this report.

Table 7-6: Market Impacts – Alternative 3S

Alternative	Levelized Cost r=6%/y	Market Impact System	Market Impact Consumer
3S South Rail	6.492 $/bbl	+1.362 $/bbl	+3.8 ¢/gal

7.4 Socioeconomic Impacts – Rail

7.4.1 Introduction

In Alternative 3, products currently carried by Line 5 are instead transferred into railcars at Superior, WI, and shipped on existing track, south through Illinois, around the southern end of Lake Michigan, over the northwest tip of Indiana, and into Michigan on a northeast route to Sarnia, Ontario. Rail transport of Line 5 product volumes would require 9 train sets of about 100 railcars each, for between 800 and 900 railcars per day, crossing 223 mi. (359 km) of Michigan.

The rail route through Michigan is slightly different from the south pipeline route design (Alternative 1). Whereas the latter enters Michigan at Berrien County, the railway enters Michigan further to the east in Cass County. It then stays to the north of the south pipeline route, never entering Macomb or Oakland counties.

Eleven Michigan counties in Prosperity Regions 6, 7, 8, 9 and 10 would be affected by the operation of a rail route moving Line 5 products from Cass to St. Clair counties. There is no new construction in Michigan associated with the rail route: the existing railway network in Wisconsin, Illinois, Indiana, and Michigan moves the product of Line 5; and the minor construction anticipated for product railcar loading and unloading occurs at the rail terminals in Wisconsin and Ontario.

Economic impacts (jobs, income, output) of south rail operation expenses are discussed in Section 7.4.2. Other socioeconomic impacts are summarized in Section 7.4.3. All socioeconomic impacts associated with Alternative 3 are discussed in greater detail in Appendix Q.

7.4.2 Operation Cost Economic Impacts

Economic multipliers (BEA RIMS II) were used to estimate the economic impacts of the south rail alternative (see Table 7-7). Once the railway system to move the current volume of Line 5 product is operational (necessary infrastructure and facilities on both ends of the rail route are built), the operation expenses to carry by rail Line 5 product from Superior to Sarnia would be about $1,220 million/y: this includes leasing and amortized capital expenses associated with the railcars. Removing the leasing and terminal expenses associated with facilities outside of Michigan, the cost to move the product from Superior to Sarnia is reduced to $672 million/y. Of that amount, $184 million/y occurs in Michigan, given that the rail crosses 223 mi. (359 km) of that state.

The direct employment impact to the state of operation expenses would be about 500 (full- and part-time) jobs. The indirect and induced economic impacts of the rail route would result in another 1,000 such jobs.

Total employment earnings from south rail operations would be about $84 million/y in earnings within the state. The total output generated by rail operations would be about $324 million/y, with value added to the Michigan economy of about $173 million/y.

Detailed results (see Appendix Q) show that as many as 920 (full- and part-time) direct and indirect jobs could be located in the rail ROW counties, accounting for as much as $56 million/y of total earnings.

Table 7-7: South Rail Route Operation Economic Impacts

Alternative 3: Use of Southern Railways			
Operation Expenses of Rail incl. WI & ON railcar leasing expenses Operation Expenses of Rail excl. WI & ON leasing & terminal charges Operation Expenses of Rail for MI portion of the route only			$1,220 million/y $672 million/y $184 million/y
Impact Area	Employment (jobs)	Labor Earnings (million $)	Output (million $)
Michigan			
Direct	491	41.9	184.1
Indirect	385	20.5	69.3
Induced	615	21.8	70.3
Total Impact	1,491	84.3	323.6
Value Added for Michigan: $173 million/y			
Notes: Economic contribution results derived using BEA RIMS II Multipliers.			

The contribution of this alternative to government revenue is estimated to be $4.05 million/y through consumer income taxes, sales taxes, and transportation fuel taxes. In addition, $8.1 million/y are estimated to accrue from railway and related facility taxes. This estimate is for Michigan as a whole, and is not attributed to counties or Prosperity Regions within the state.

7.4.3 Social Impact Screening

For each alternative, Appendix Q provides socioeconomic analysis for SIA screening; the results of which are summarized in Table Q-6 (see Appendix Q). Under Alternative 3, the SIA screening for operation of a south rail route draws particular attention to infrastructure disturbance impacts (traffic circulation), and community concerns related to noise and safety.

Land cover data show that the south rail route passes through areas of low urbanization. However, the design of this alternative involves an increase in daily rail traffic of 9 trains of 100 cars each. With such an increase, all road/street crossings along the route will be subject to more delays from train traffic. Train-related noise along the length of the rail line will increase. Concerns for human and animal safety will be increased with the increased frequency and volume of rail traffic. An SIA would need to determine the significance of these impacts to communities along the rail route.

The screening conducted in this report is a preliminary assessment and has not included any public processes to define concerns and develop potential mitigation measures. Mitigation measures for concerns are usually developed closer to more detailed stages of project implementation.

7.5 Spill Risk Assessment – Rail

As illustrated in the following Table, a number of recent crude-by-rail accidents in both the U.S. and Canadian has heightened the awareness of crude-by-rail risks among the general public, regulators, and first responders. [144] In particular, the July 2013 derailment of a train operated by the MM&A Company, carrying North Dakota crude in Lac-Mégantic, Québec, Canada, which resulted in 47 fatalities has caused significant concern about the safety of crude-by-rail transportation. [145, p. Table 1]

Table 7-8: Summary of Recent Crude-by-Rail Accidents

Date	Location	Spill Volume (bbls)	Fire	Details of Significant Impacts
June, 2016	Mosier, OR	1,000	Yes	Several cars burned. Some oil entered Columbia River.
Mar, 2015	Gogama, ON	69	Yes	-
Feb, 2015	Gogama, ON	35	Yes	-
Feb, 2015	ON	Unknown	Yes	-
Feb, 2015	AB	None	No	-
Feb, 2015	Boomer Bottom WV	9,800	Yes	Train derailment with 27 cars spilled oil into Kanawha River; source of drinking water in two counties. 19 cars involved in fire
Dec, 2014	Calgary, AB	640	Yes	-
May, 2014	LaSalle, CO	155	No	-
Apr, 2014	Lynchburg, VA	1,190	Yes	3 cars burned, no injuries, but some oil in river. Immediate area evacuated.
Feb, 2014	WI / MN	286	No	-
Feb, 2014	Vandergrift, PA	108	No	-
Jan, 2014	Plaster Rock, NB	Unknown	Yes	5 tank cars exploded and burned 45 homes evacuated – no injuries
Dec, 2013	Casselton, ND	>9,524	Yes	20 Tank cars exploded and burned. 1,400 residents evacuated – no injuries
Nov, 2013	Aliceville, AL	17,820	Yes	~12 tank cars burned – no injuries
Oct, 2013	Gainford, AB	Unknown	Yes	100 residents evacuated – no injuries
Jul, 2013	Lac-Mégantic, QC	631	Yes	63 tank cars derailed, leading to multiple explosions and fires. 47 fatalities, 2,000 evacuated
March, 2013	Parkers Prairie, MN	714	No	-

Public awareness and concern was heightened by the sudden increase in the amount of oil transported by rail in the US after the year 2009. [144, p. Figure 2]

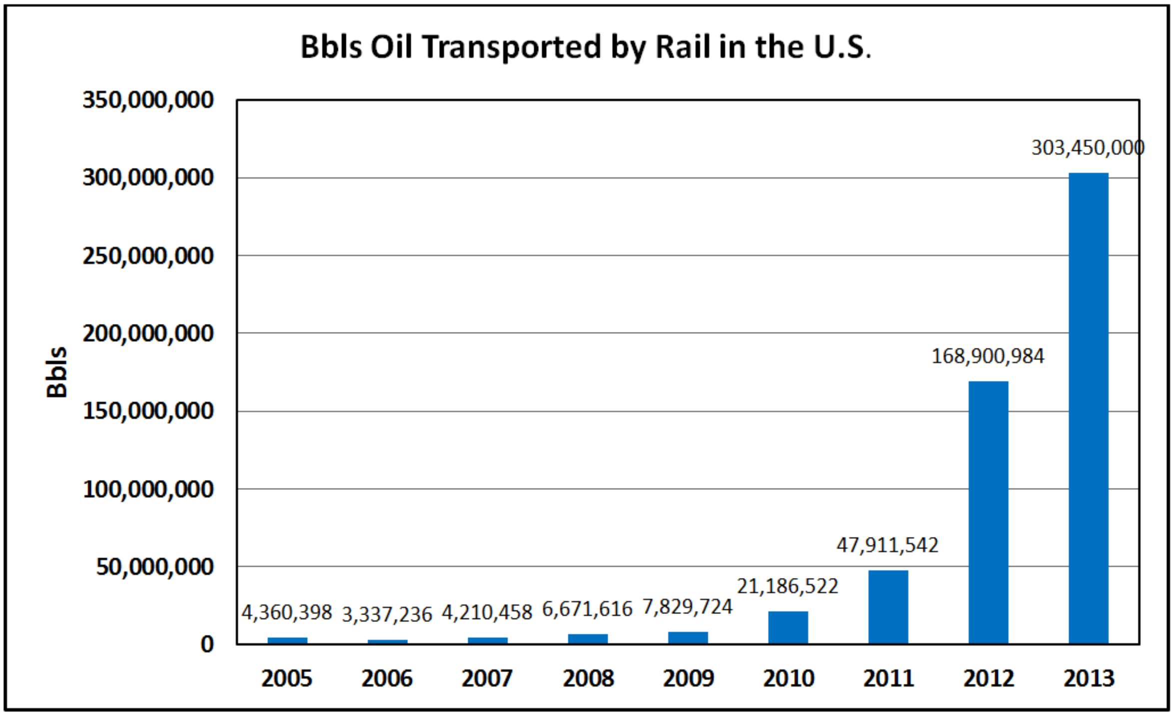


Figure 7-2: Barrels of Oil Transported by Rail in the United States

7.5.1 Failure Probability and Volume Analysis

The objective of the Failure Probability and Volume Analyses - Rail is to calculate the expected annual frequency or probability that spill events of various sizes might occur with the crude-by-rail transport associated with the hypothetical replacement of the Straits Crossing with an alternative pipeline segment that does not cross the Great Lakes.

7.5.1.1 Methodology

In the United States, the main source of railroad accident data is the Federal Railroad Administration (FRA), an agency of the US Department of Transportation. However, estimating crude-by-rail accident rates is challenging due to the lack of availability on specific data on national crude-by-rail track mileage. Nevertheless, numerous studies exist that provide estimates of crude-by-rail accident rates, and these were used as the basis of both the frequency as well as volume analysis. [144], [146], [147]

The alternative involving the shipment of Line 5's oil by rail will involve the utilization of unit trains (trains of 100 to 120 tank cars that solely contain crude oil). Because crude-by-rail transport utilizing unit trains is a relatively new phenomenon of the last ten years, data on accidents specifically involving crude-by-rail shipments by unit trains are not readily available from the FRA, and there are a limited number of studies specifically geared towards crude-by-rail accidents and spills. The failure rates and volume analysis was based on the references cited above because they address unit train accident rates.

Carlson [147] provided estimates of accident rates for crude-by-rail utilizing unit trains ranging from 0.81 – 2.08 incidents per billion ton-miles, with spill volumes ranging from

16.4 – 65.7 bbl per incident. Using the mid-point of each range as being representative of average values, the average incident rate is 1.45 incidents per billion ton-miles, and the average spill volume is 41.1 bbl per incident. Table 7-8 is instructive from the point of view of establishing a reasonable upper-bound estimate of spill volume. Based on a review of that Table, it can be seen that a reasonable upper upper-bound estimate of spill volume is 10,000 bbl per spill incident. This value is bracketed by Etkins' estimates of worst-case spill volumes, which range from 8,014 bbl to 14,547 bbl [144, p. 10]. As a typical rail tank car holds 714 bbl, a spill volume of 10,000 bbl represents spillage from 14 tank cars.

7.5.1.2 Results

Based on the above, and assuming a haul length of 813 mi. (1,308 km), along with an average product specific gravity of 0.797[33], and a capacity of 540,000 bbl/day, the annual number of ton-miles of oil that would be transported by rail is 2.24 x 10^{10}. At an incident rate of 1.45 incidents per billion ton-miles, this yields an annual incident rate of 32.5.

While the average spill volume is 41.1 bbl, Etkin showed that the median spill volume ranges from 328 to 596 bbl (the mid-point of which is 462 bbl). Therefore, for the purposes of characterizing risk, it is more realistic to consider a spill volume of 462 bbl, with a frequency calculated as 32.5 x [41.1/462] = 2.891 spills per year. The oil spill frequency = 2.891x0.888 = 2.567 oil spills/year (with the value 0.888 representing the mass-fraction of oil shipped along Line 5, based on a 1/6:5/6 NGL/Oil volume fraction).

7.5.2 Spill Consequence Analysis

For the purposes of the environmental fates and effects analysis, only releases of oil are considered, as NGLs (which are principally propane) do not persist in the environment.

7.5.2.1 Release Analysis

While as stated above, the average volume of release is 41.1 bbl/incident, Etkin [144, p. 10] showed that the median spill volume ranges from 328-596 bbl (the mid-point of which is 462 bbl). Therefore, for the purposes of characterizing environmental risk, it is more realistic to consider a spill volume of 462 bbl with a frequency calculated as 32.5 x [41.1/462] = 2.891 spills per year. The *oil* spill frequency is therefore determined as 2.891 x [mass fraction of oil (=0.888)] = 2.567 oil spills/year.

7.5.2.1.1 Methodology

The annual frequency at which oil spills of 462 bbl will impact environmentally sensitive areas was determined as the annual oil spill frequency of 2.567 x [(length of environmentally sensitive areas)/(total rail line length)].

[33]The values for the average product specific gravity and the mass fraction of oil are based on an assumed breakdown of product by:

- volume of 1/5 NGLs (5/6 oil, an average daily throughput of 540,000 bbl/d)
- a specific gravity for NGLs of 0.535
- a specific gravity for oil of 0.85.

The annual frequency at which oil spills of 462 bbl will impact Non-environmentally sensitive areas was determined as the annual oil spill frequency of 2.567 x [(length of Non-environmentally sensitive areas)/(total rail line length)].

The length of environmentally sensitive areas, selected to be aquatic areas (rivers, streams canals and wetlands), was determined via GIS extrapolations carried out for the environmental consequence analyses in Section 7.5.2.3.1.

The length of non-sensitive environmental areas was simply the length of the rail line minus the length of traversed environmentally sensitive areas. More explanation for this is given in the respective section.

7.5.2.1.2 Results

Table 7-9 presents the annual spill frequency of 462 bbl into environmentally-sensitive and non-environmentally-sensitive areas for the rail alternative.

Table 7-9: Annual Spill Frequency from Rail Failure

	Annual Spill Frequency (spills/year)	
State	Environmental Sensitive Areas	Non-Environmental Sensitive Areas
Michigan	0.059	0.645
Illinois	0.018	0.329
Indiana	0.006	0.249
Wisconsin	0.227	1.033
Overall	0.310	2.257
*Based on assumed average river, stream and canal width of 82.02 ft, 3.28 ft and 8 ft respectively.		

The relative impacts resulting from occurrence of such an event are further discussed in the following section.

7.5.2.2 Oil Spill Analysis

The environmental consequence analysis focused on identifying key loss of containment along the ‘Rail’ spill exposure pathways / receptors and qualitatively assessing environment consequences in relation to probable spill volumes and frequencies (see above section). Particular attention was placed on aquatic environments, i.e. which were considered as indicators of ‘environmentally sensitive areas’ in the Great Lake region due to the higher chance of rapid and widespread dispersion. This generally includes wetlands [148], other palustrine environments (i.e. marsh, muskeg, etc.) [149], freshwater rivers, canal and streams [150].

Other areas where a spill or leak could more readily be contained and cleaned-up were analyzed but considered as lesser or non-sensitive environments. This includes:

- Protected areas: Protected open space in the United States with gap status 1-3 [151]
- Urban areas: Highly Populated Areas (HPAs) where there are 50,000 people or more [152]

- Public water supply system: Well Head Protection Area which represents the land surface area that contributes ground water to wells serving public water supply systems throughout Michigan [153]

Potential key environmental pathways / receptors that could be exposed to the acute or chronic hazards related loss of containment event were identified via GIS overlay and extrapolations techniques for Michigan counties and potentially other affected States. The generated GIS output covered:

- locations and quantities of river and stream crossings
- locations and quantities of drainage crossings
- location and lengths of transected ‘wetland areas’
- location and transected ‘protected areas’
- location of the alternative rail route in relation to where drinking water could be a risk
- location and length of transected urban areas.

With the above identification of exposure characteristics, project experts then outlined the potential scale of consequences related to the most exposed environmental receptors.

7.5.2.2.1 Discussion: Behavior of Released Oils

A detailed discussion on the behavior of released oil is given in Section 6.5.2.2.1 giving an overview of key physiochemical variables that influence an oil spill and an explanation of the acute and chronic impacts associated with them.

7.5.2.2.2 Discussion: Sensitive Aquatic Environments

The Rail Alternative would entail transporting high volumes of oils and NGLs over aquatic environment, where statistical analysis indicates that 462 bbls could be spilled with an Annual Spill Frequency ranging between 0.006 and 0.227 in the 4 traversed States. Table 7-10 provides an overview of intersected aquatic environments in these States; namely rail line crossings of rivers, streams and wetland spill exposure pathways / receptors.

Table 7-10: Overview of Rail Intersected Aquatic Environments

State / County		Number of Crossings			Wetland Crossings		Pathway, Receptors Names & Descriptions	
		Rivers	Stream	Canal	Number	Length (mi.)	Rivers	Wetlands
Michigan	Calhoun	-	-	-	85	1.20	-	Where applicable the 3 largest wetland types intersected, incl. - Riverine - Freshwater Forested / Shrub Wetland - Freshwater Emergent Wetland
	Cass	1	1	0	118	1.41	Rocky River	
	Eaton	1	1	0	166	0.63	Thornapple River	
	Genesee	0	9	2	73	0.57	N/A	
	Ingham	0	2	0	97	1.97	N/A	
	Kalamazoo	1	2	0	150	1.79	Portage River	
	Lapeer	2	4	2	149	2.73	North Branch Belle River	
	Shiawassee	1	2	1	157	2.46	Looking Glass River	
	St. Clair	5	0	0	75	5.69	Pine River, South Branch Pine River	
	St. Joseph	0	0	1	12	0.01	N/A	
	Total	11	21	6	1,082	18.46	N/A	
Illinois		2	37	0	562	5.64	Des Plaines River, DuPage River	- Bottomland Forest - Deep Marsh - Perennial Deepwater River
Indiana		3	12	14	313	1.93	St. Joseph River, Deep River, Little Kankakee River	- Riverine - Freshwater Forested / Shrub Wetland - Freshwater Emergent Wetland
Wisconsin		54	57	1	3,693	71.27	Many[34] such as the Wolf, Rock River and Wisconsin River	- Riverine - Freshwater Forested / Shrub Wetland - Freshwater Emergent Wetland

34 Amnicon River, Bark River, Black River, Chippewa River, East Branch Fond Du Lac River, East Branch Rock River, Eau Claire River, Fisher River, Flambeau River, Fond du Lac River, Fox River, Jump River, Little Jump River, Little Thornapple River, Middle River, Mukwonago River, Namekagon River, North Fork Eau Claire River, Plover River, Popple River, Rat River, Saint Croix River, South Fork Popple River, Thornapple River, Tomorrow River, Totagatic River, Waupaca River, West Branch Fond Du Lac River, White River, Wisconsin River, Wolf River, Yellow River

As apparent from the table, of the 4 States where rail transport would occur, Wisconsin would be the most exposed to the aquatic spills with 54 river and 57 stream crossings; and a cumulative length of approximately 71 mi. of wetland classified land intersected. As may be expected, due to the length of the Rail Alternative line in the state, Michigan would experience the second highest level of spill exposure with 11 rivers, 11 streams, and 6 drainage canals crossed; as well as approximately 6 to 7 mi. of wetlands traversed. Despite Indiana having the most drainage canals crossed and Illinois the second most streams crossed at 37, both states would experience lower levels of risk to aquatic habitats. It should nevertheless be pointed out that the closer proximity of these rivers, streams and drainage canals to Lake Michigan in these states could entail a greater risk of oil spill dispersion and environmental consequences to it.

Further discussion on the specific risk and potential environmental consequences from the Rail Alternative aquatic spills to the State of Michigan are shown (see Figure 7-3) and discussed below.

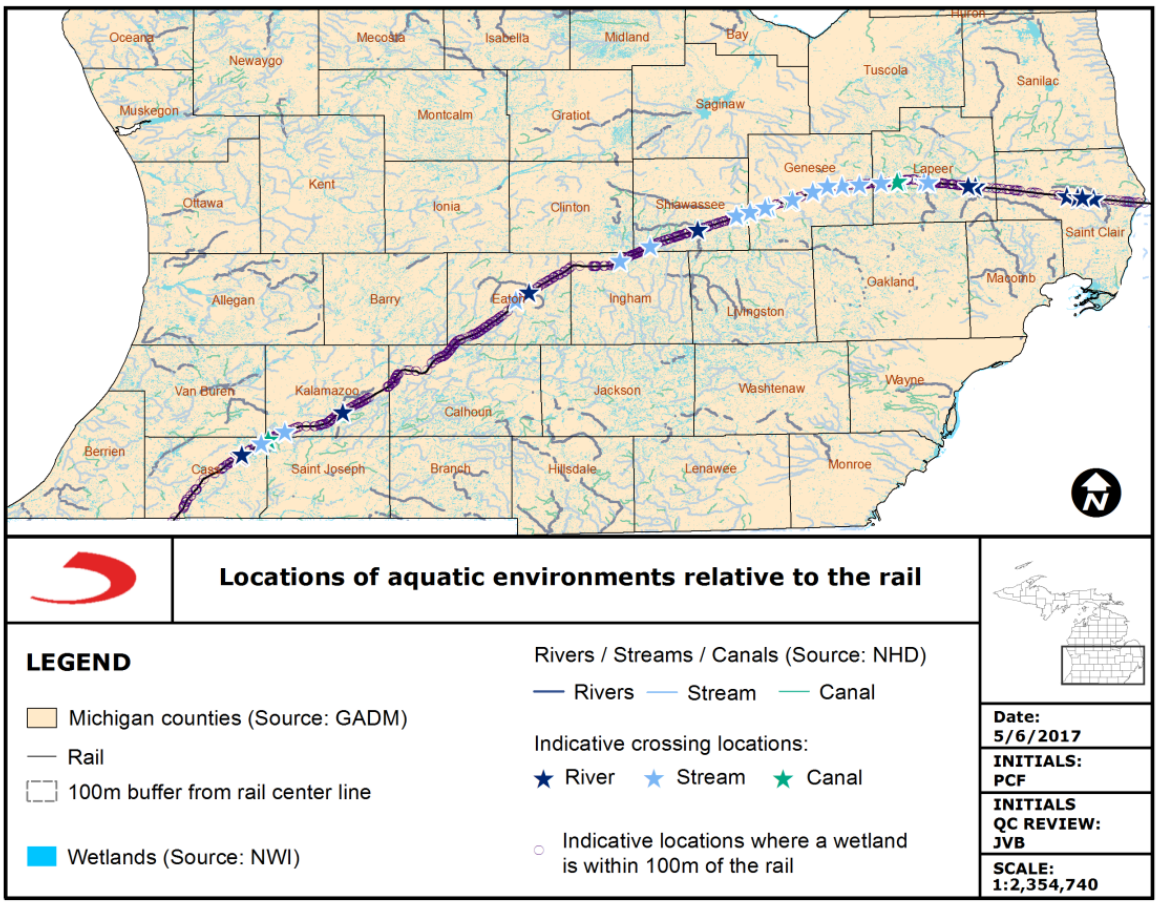


Figure 7-3: Illustration of Rail Intersected Aquatic Environments in Michigan [150], [154]

As evident, the Rocky, Thornapple, Portage, North Branch Belle, Looking Glass, Pine River, Branch Pine Rivers would be all be crossed with a higher frequency of oil transport. In addition, significant areas of mainly Riverine, Freshwater Forested / Shrub

Wetland, and Freshwater Emergent Wetland could incur the consequences of a statistically possible spill. While it is beyond this document to fully elucidate on the wide variety and scale of environmental impacts that could occur from such a spill, a review of Michigan Department of Environmental Quality literature [155] indicates that many Michigan wetlands, particularly in southern Lower Michigan, are rare and as such, consist of generally higher portions of state rare or endangered species. For example, 28 rare plants and 20 rare animals have been recorded from the Lakeplain Wet Prairie along the shores of Lake Huron in Saginaw Bay, within the delta of St Clair River. Michigan is also one of the three states where inland salt marshes (habitat classified as extreme rarity) still persist, containing rare plant species such as the Dwarf spike-rush and Three-square bulrush, both of which are state endangered [156]

As apparent in Section 7.5.2.2.1, oil spills can behave in very different ways depending on a particular aquatic environment. For example, Lakeplain prairies usually experience seasonal flooding throughout the year. These glacial lakeplains have a clay layer situated one to three meters below highly permeable sand that impedes drainage, resulting in temporary flooding in the winter and spring and drought in summer and fall. Seasonal changes in flows such as this and the generally meandering rivers of south Michigan suggest a vast range of oil spill weathering and impacts scenarios. It is nevertheless clear that a 462 bbls spilled directly on, or via dispersion into, palustrine and other aquatic environment would cause significant environmental damage that would be particularly difficult to contain and clean-up. The consequence to remaining wetland habitat and the rare or conservationally important species that they support would most certainly be significant.

7.5.2.2.3 Discussion: Lesser Sensitive / Non- Sensitive Receptors

The Rail option would also entail transporting higher volumes of oil over non-aquatic habitats; such as various urban areas, agricultural land, industrial areas and areas designated as ‘Protected’. The use of ‘non- environmental sensitive’ receptors in this document is therefore an over simplification of the possible impacts that could occur but, as mentioned, was used as spills or leaks could more readily be contained and cleaned-up.

Table 7-11 provides an overview of the representative terrestrial receptors, i.e. Protected, HPA Urban, and Drinking Water Resource areas.

Table 7-11: Overview of Intersected (100 m Buffer) Non-Environmentally Sensitives Areas

State / County		Protected Areas		Urban Areas (HPA)		Drinking Water Resources		(Example) Receptors Names
		Number	Length (mi.)	Number	Length (mi.)	Number	Length (mi.)	
Michigan	Calhoun	-	-	1	11.20	2	N/A	HPAs: Battle Creek Drink Res.: Battle Creek
	Cass	1	N/A	1	2.00	4	N/A	Prot. Areas: Tamarack Swamp Portfolio Site Fee HPAs: South Bend Drink Res.: Cassopolis, Marcellus
	Eaton	4	1.05	1	4.62	6	N/A	Prot. Areas: Windsor Township State Wildlife Property HPAs: Lansing Drink Res.: Charlotte, Lansing, Windsor Estates
	Genesee	-	-	1	23.09	7	N/A	HPAs: Flint Drink Res: Several mobile home parks, Davison (well 2, 5 & 6)
	Ingham	1	N/A	1	18.30	3	N/A	HPAs: Lansing Drink Res.: East Lansing Meridian Water Authority, Lansing Township
	Kalamazoo	-	-	1	7.02	5	N/A	HPAs: Kalamazoo Drink Res.: Vicksburg, Steward Sutherland
	Lapeer	2	N/A	-	-	7	N/A	Drink Res.: Lapeer County Health Dept., Maple Grove Elementary School, The Scotts Company
	Shiawassee	2	N/A	-	-	10	N/A	Drink Res.: Countryside Village MHP, Morrice Meadows
	St. Clair	4	2.10	1	6.58	-	-	HPAs: Port Huron
	Total	14	3.15	7	72.81	44	N/A	N/A
Illinois		13	1.94	2	108.54			Prot. Areas: Pratts Wayne Roods, Loon Lake, Cedar Lake HPAs: Chicago, Round Lake Beach
Indiana		6	N/A	2	40.76			Prot. Areas: Kingsbury Fish and Wildlife Area, LaPorte, Fish Creek Fen Site Fee HPAs: Chicago, South Bend
Wisconsin		28	18.49	7	50.00			Prot. Areas: SACN, Scenic Easement, St. Croix National Scenic Riverway HPAs: Appleton, Duluth, Milwaukee, etc.

Protected areas [151] were included in the analysis as they can entail conservational, recreational, landscape and other environmental attributes (i.e. it is also noted that they can include aquatic environments). From the above table, it is evident that the length of the Rail line through Wisconsin leads to the highest number of incidences and the longest length where a buffered Rail line would come in contact with or directly bisect a Protected Area as defined Protected Areas Database of the United States[35]. Michigan again experiences the second highest level of occurrences with 14, where two direct crossings of Protected Areas occur in Eaton and St. Clair Counties totals 3.1 mi. (see also Figure 7-4 below). An oil spill near these areas would clearly hinder or damage the protected attributes for which these areas were designated.

In relation to Highly Populated Areas (HPAs) [152], urban areas in Chicago make Illinois the most exposed to spill related urban impacts (e.g. temporary loss of access to a spill area or more remote possibility of health effects or damage to private property). Here, the alternative Rail line crosses 2 HPAs totaling 108 mi. in length. This is followed by Michigan with approximately 72 mi. of traversed HPA areas spread over 7 crossings. With the longest length of Rail line, Wisconsin would have the 3rd highest exposure at 50 mi., followed closely by Indiana at approximately 41 mi.

Social impacts to terrestrial receptors is perhaps more obvious in relation to the oil spill related loss of access to drinking water or the possible health impacts from resulting contamination of groundwater, wells or aquafers. Using the Well Head Protection Area Dataset [153] , which represents the land surface area that contributes ground water to wells serving public water supply systems throughout Michigan, analysis showed that 44 protected drinking water resource areas would be exposed to a Rail oil spill (see Table 7-11 above and Figure 7-4 below).

[35]Official Protected Open Spaces - U.S. Geological Survey, Gap Analysis Program (GAP). May 2016. Protected Areas Database of the United States (PAD-US), version 1.4 Combined Feature Class.

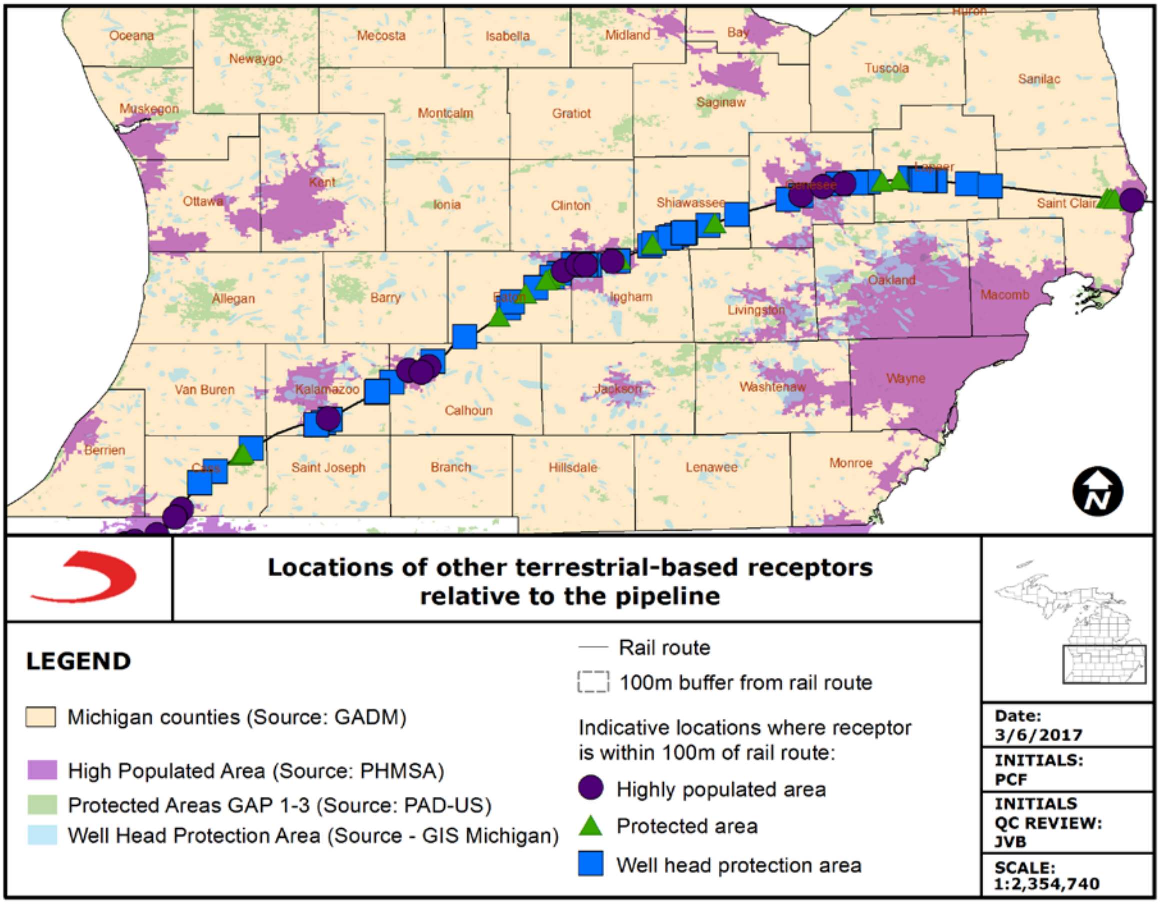


Figure 7-4: Illustration of Rail Intersected Terrestrial Receptors in Michigan

The statistical calculations of Spill Frequency presented in Section 7.5.2.1.2 were not specific to these receptors due to the aforementioned diversity in receptors categories. It is nevertheless clear that there are sensitive in the non-environmentally sensitive terrestrial length of Rail line exposed to an Annual Spill Frequency of 2.35 in Michigan.

7.5.2.3 Economic Consequence

The economic analysis of the spill costs involves the direct estimation of cleanup costs and a factored estimate for eventual damages. In simplest terms:

Total Spill Costs = Total Response & Clean-up Costs + Total Damage Costs

The response and cleanup costs are a function of factors such as spill remoteness, spill size, amount of onshore oiling, type of cleanup technique used, time of year, and oil density and chemistry. Cleanup costs are also affected by the nature of onshore areas that are impacted by the spill. The damage estimate reflects potential longer term social and environmental costs associated with damages to natural resources, restoration of environmental functions, and impacts on both commercial and subsistence resource harvesting.

The spill cost modeling provides linear and non-linear functions for a number of the factors associated with the spill. The model is based on historical experience with spills in the US and with global maritime spills. The model is particularly appropriate for the estimation of hypothetical spills, as it is based on statistical findings related to global spills over the past three decades. The model excludes fines and penalties associated with a spill event.

7.5.2.3.1 Methodology

As further described in Appendix R, the project interpreted land-use along the rail corridor to assess the economic consequence of spills within HCAs.

The definition of an HCA used in this study includes four classes: HPAs, OPAs, ESAs and OSAs.

HPAs and OPAs are derived from PHMSA information based on the 2010 census and serve as guidance for routing design in the pipeline industry. Populated areas are regarded as an HCA because a large class of social damages that show as compensated damages in spill cost data are tied directly or indirectly to environmental resources: water contamination, soil contamination, damaged belongings, and lost access to resources or recreational opportunities are all more acute in populated areas.

ESAs are based on all categories included within the U.S. National Wetlands Inventory, including navigable waters. Wetlands are an appropriate basis for estimating damages because wet areas generally have the highest value in NRDAs used in oil spill damage claims.

OSAs are defined within this study as 10% of the above classes and are intended to reflect a broad range of otherwise HCAs that may not be captured by the HPA, OPA, and ESA designations. For example, the GIS interpretation also identified potentially culturally important heritage sites that are proximate to the corridors, but are represented by a single point rather than a linear feature or aerial feature. Also, most routings of any infrastructure potential include cultural or traditional uses that are identified only when detailed route planning is commenced and affected groups are consulted. A contingency for OSA is thus used to reflect these potential areas.

For all spills, a weighted average of spill costs was calculated based on the proportion of the corridor intersecting an HCA; spill costs in an HCA are generally higher than those not in an HCA.

Intersects of HCAs by the rail corridor were calculated using two methods. Direct intersects are the linear distance (in miles) of the rail corridor with a land-use type classified as an HCA. Indirect intersects reflect a broader area-based measure (in square miles) defined by a corridor that extends outwards from the centerline of the infrastructure. Rail lines that cross a river would count just the crossing length in their *direct HCA proportion*; those following alongside a river on one bank might follow a river for miles, yet show zero direct intersect. The indirect measure is therefore regarded as appropriate for most spill modeling with potentially significant consequences.

This study applies an indirect approach for moderately large oil spills (>1,000 bbl). The oil spill model, however, also makes one exception to this approach for smaller spills. Some proportion of all spills typically stays within the bounds of operating company property or an already modified ROW. For small spills, therefore, the use of indirect GIS interpretive methods tends to overstate spill risk because the HCA designation would include the ROW as a HCA even though it is not associated with a high consequence. The spill model used in this study therefore uses the direct intersect measure for pipeline spills under 1,000 bbl; these are regarded as providing a more accurate representation of potential impacts of a hypothetical release.

7.5.2.3.2 Results

The resultant interpretations of the analysis of oil spills along the rail corridor indicate that the HCA proportion along that corridor is 66.55%.

This proportion is for the entire rail corridor. Readers are reminded that the environmental consequences are described for this corridor as a whole; the consequences inside any given state are not estimated.

7.5.2.4 Environment Consequence

As outlined in Section 1.9.5, and for the purposes of characterizing and comparing the environmental risk between the various alternatives considered in this report, by convention, the environmental component of economic consequence has been adopted to represent environmental consequence. This measure of environmental consequence is based on a monetization of the damages, which in principle encompass the following impacts, provided that these impacts can be directly associated with a spill event:

- Restoration costs of the natural environment.
- A broad range of environmental damages normally included within an NRDA, including air, water and soil impacts.
- Net income foregone in the sustainable harvest of a commercial resource.
- Net value foregone in the sustainable harvest of a subsistence resource, including fisheries.

The quantified elements of spill cost reflect an expected value of damages contingent upon the occurrence of an initial spill event.

7.5.2.4.1 Methodology

As further described in Appendix R, the project interpreted land-use along the rail corridor to assess the consequence of spills within HCAs.

The definition of an HCA used in this study includes four classes:

- HPAs
- OPAs
- ESAs
- OSAs.

HPAs and OPAs are derived from PHMSA information based on the 2010 census and serve as guidance for routing design in the pipeline industry. Populated areas are regarded as HCAs because a large class of social damages that show as compensated damages in spill cost data are tied directly or indirectly to environmental resources:

water contamination, soil contamination, damaged belongings, and lost access to resources or recreational opportunities are all more acute in populated areas.

ESAs are based on all categories included within the U.S. National Wetlands Inventory, including navigable waters. Wetlands are an appropriate basis for estimating damages because wet areas generally have the highest value in NRDAs used in oil spill damage claims.

OSAs are defined within this study as 10% of the above classes and are intended to reflect a broad range of otherwise HCAs that may not be captured by the HPA, OPA, and ESA designations. For example, the GIS interpretation also identified potentially culturally important heritage sites that are proximate to the corridors, but are represented by a single point rather than a linear feature or areal feature. Also, most routings of any infrastructure potential include cultural or traditional uses that are identified only when detailed route planning is commenced and affected groups are consulted. A contingency for OSA is thus used to reflect these potential areas.

For all spills, a weighted average of spill costs was calculated based on the proportion of the corridor intersecting an HCA; spill costs in an HCA are generally higher than those not in an HCA.

Intersects of HCA by a rail corridor were calculated using two methods. Direct intersects are the linear distance (in miles) of the rail corridor with a land-use type classified as an HCA. Indirect intersects reflect a broader area-based measure (in square miles) defined by a corridor that extends outwards from the centerline of the infrastructure. Rail lines that cross a river would count just the crossing length in their *direct HCA proportion*; those following alongside a river on one bank might follow a river for miles, yet show zero direct intersect. The indirect measure is therefore regarded as appropriate for most spill modeling with potentially significant consequences.

This study applies an indirect approach for moderately large oil spills (>1,000 bbl). The oil spill model, however, also makes one exception to this approach for smaller spills. Some proportion of all spills typically stays within the bounds of operating company property or an already modified ROW. For small spills, therefore, the use of indirect GIS interpretive methods tends to overstate spill risk because the HCA designation would include the ROW as an HCA, even though it is not associated with a high consequence. The spill model used in this study therefore uses the direct intersect measure for pipeline spills under 1,000 bbl. These are regarded as providing a more accurate representation of potential impacts of a hypothetical release.

7.5.2.4.2 Results

The resultant interpretations of the analysis of oil spills along the rail corridor indicate that the HCA proportion along that corridor is 66.55%.

This proportion is for the entire rail corridor. Readers are reminded that the environmental consequences are described for this corridor as a whole; the consequences inside any given state are not estimated.

7.5.3 Risk Calculation

7.5.3.1 Health and Safety Risk

7.5.3.1.1 Methodology

An analysis transportation incident rates based on U.S. Department of Transportation data for the years 2002 – 2009 cites an average of 2.4 fatalities and 4.6 hospitalizations (operator personnel and general public) associated with the transportation of 23.9 billion ton-miles of petroleum transported by rail. [157, pp. Tables 8-10] This equates to 0.100 fatalities and 0.193 hospitalizations per billion-ton miles.

7.5.3.1.2 Results

Based on the above statistics, with the transport of 2.24×10^{10} ton-miles of Line 5 products transported by rail annually, the expected average number of fatalities per year is 2.24, and the expected average number of hospitalizations per year is 4.32.

7.5.3.2 Economic Risk

7.5.3.2.1 Methodology

The spill incident rate associated with the transportation of Line 5 volumes by rail is provided in Section 7.5.1.2.

Economic Risk (R_{Econ}, \$/y) was determined in accordance with Equation 7-1.

$$R_{Econ} = \left[\left(R_S \times F_{HCA} \times \$_{HCA}\right) + \left(R_S \times \left(1 - F_{HCA}\right) \times \$_{Non-HCA}\right)\right]$$

Equation 7-1: Calculation of Economic Risk

Where:

R_S = Annual rail oil spill frequency (= 2.567 per Section 7.5.1.2)

F_{HCA} = HCA proportion along the rail corridor (= 0.6655 per Section 7.5.2.4.2)

$\$_{HCA}$ = Economic consequences associated with a rail spill in an HCA (= \$21,970,000 per Appendix R)

$\$_{Non-HCA}$ = Economic consequences associated with a rail spill in a Non-HCA (= \$14,200,000 per Appendix R)

7.5.3.2.2 Results

From Equation 7-1, the Economic Risk associated with Alternative 3 was determined to be $49,723,000/y.

7.5.3.3 Environmental Risk

7.5.3.3.1 Methodology

The spill incident rate associated with the transportation of Line 5 volumes by rail is provided in Section 7.5.1.2.

Environmental Risk (R_{Env}, \$/y) was determined in accordance with Equation 7-2.

$$R_{Env} = \left[\left(R_S \times F_{HCA} \times \$_{HCA}\right) + \left(R_S \times \left(1 - F_{HCA}\right) \times \$_{Non\text{-}HCA}\right)\right]$$

Equation 7-2: Calculation of Environmental Risk

Where:

R_S	=	Annual rail oil spill frequency (= 2.567 per Section 7.5.1.2)
F_{HCA}	=	HCA proportion along the rail corridor (= 0.6655 per Section 7.5.2.4.2)
$\$_{HCA}$	=	Monetized environmental consequences associated with a rail spill in an HCA (= \$8.09 million per Appendix R)
$\$_{Non\text{-}HCA}$	=	Monetized environmental consequences associated with a rail spill in a Non-HCA (= \$5.22 million per Appendix R)

7.5.3.3.2 Results

From Equation 7-2, the Environmental Risk associated with Alternative 3 was determined to be 18,300,000/y.