A Spill Risk Assessment of the Enbridge Northern Gateway Project

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Executive Summary

1. The objective of this report is to evaluate Enbridge's spill risk analysis and to determine if spills from the ENGP are likely to cause significant adverse environmental effects as defined by the *Canadian Environmental Assessment Act* (*CEAA*).

2. The *CEAA* evaluation criterion requires assessment of two components to define risk: the severity of an adverse impact and the likelihood of an adverse impact occurring. This report focuses on evaluating the likelihood of an adverse impact (oil spills) occurring. Another report completed by Gunton and Broadbent (2012b) addresses the severity of the impact of an oil spill and concludes that oil spills as small as 238 m^3 (1,500 barrels) could have significant adverse environmental impacts.

3. The ENGP consists of an 1,172 kilometre (km) oil pipeline to ship oil from Alberta (AB) to Kitimat, British Columbia (BC), a condensate pipeline to ship condensate from Kitimat to AB, and a marine terminal for tankers. The planned capacity of the oil pipeline is 525 thousand barrels per day (kbpd) with potential to expand to 850 kbpd and the planned capacity of the condensate pipeline is 193 kbpd with potential to expand to 275 kbpd. The ENGP would require an average of 220 tankers per year, which could increase to 331 tankers per year with expansion of the pipeline to full capacity.

4. Enbridge provides separate estimates of the likelihood of spills for each of the three major components of the project: tanker operations, terminal operations, and the oil and condensate pipelines. Enbridge does not combine these separate estimates to provide an overall estimate of the probability of spills for the entire project and therefore does not provide sufficient information to determine the likelihood of adverse environmental effects as required by *CEAA*.

5. Forecasting spill risk is challenging due to the many variables impacting risk and the uncertainties in forecasting future developments affecting risk. To improve the accuracy of risk assessment, international best practices have been developed. This report uses these international risk assessment best practices to evaluate Enbridge's methodology for estimating spill rates for the ENGP based on the following rating scale:
   - *Fully met*: no deficiencies
   - *Largely met*: no major deficiencies
   - *Partially met*: one major deficiency
   - *Not met*: two or more deficiencies.

6. The evaluation concludes that Enbridge's spill risk analysis meets none of the seven best practice criteria (Table ES-1). In total there are 28 major deficiencies in the Enbridge risk analysis for ENGP tanker, terminal and pipeline spills. The results show that Enbridge understates the risk of spills from the ENGP.

Table ES-1: Results for the Qualitative Assessment of Spill Estimates for the ENGP

Criterion	Major Deficiencies	Result
Transparency *Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk*	*1.* Lack of supporting evidence for LRFP tanker incident frequency data *2.* Insufficient evidence supporting conditional probabilities for tanker spills *3.* Limited transparency in the application of local scaling factors to the BC study area *4.* Lack of information comparing incident frequencies at Kitimat Terminal to marine terminals in Norway *5.* Lack of transparency in documenting how mitigation measures will reduce the likelihood of tanker and terminal spills *6.* Inadequate evidence supporting the reduction of spill frequencies for pipeline operations	**Not Met**
Replicability *Documentation provides sufficient information to allow individuals other than those who did the original analysis to obtain similar results*	Insufficient proprietary data and information required to replicate: *7.* Incident frequencies for tanker accidents *8.* Scaling factors for ENGP routes *9.* Probabilities and spill volume estimates for tanker spills, *10.* Mitigation measures for tanker and terminal operations *11.* Pipeline incident frequencies	**Not Met**
Clarity *Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision making*	*12.* Failure to effectively communicate the probability of spills over the life of the project *13.* Failure to combine estimates for tanker, terminal, and pipeline spills to present a single spill estimate for the entire project *14.* Failure to determine the likelihood of all spill size categories that can have a significant adverse environmental impact *15.* Lack of clear communication of spill estimates generated in detailed technical data reports in the main ENGP application *16.* Failure to address the effective implementation of mitigation measures that reduce risk	**Not Met**
Reasonableness *The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment*	*17.* Inappropriate definition of the study area to estimate spill return periods for tanker operations *18.* Reliance on tanker incident frequency data that underreport incidents by between 38 and 96%. *19.* Potential double-counting of mitigation measures for LRFP tanker incident data *20.* Inadequate consideration of the corrosiveness of diluted bitumen associated with internal corrosion that may increase spill probability *21.* Failure to consider different vessel characteristics in tanker incident frequencies	**Not Met**
Reliability *Appropriate analytical methods explicitly describe and evaluate sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk*	*22.* Failure to provide confidence intervals that communicate uncertainty and variability in spill estimates for tanker, terminal, and pipeline operations *23.* Failure to complete an adequate sensitivity analysis that effectively evaluates uncertainty associated with spill estimates	**Not Met**
Validity *Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis*	*24.* Inadequate expert review and validation of spill estimates for tanker, terminal, and pipeline operations *25.* Experts in the review and validation of spill estimates lack independence and third-party status	**Not Met**
Risk Acceptability *Stakeholders identify and agree on acceptable levels of risk in a participatory, open decision-making process and assess risk relative to alternative means of meeting project objectives*	*26.* Failure to define risk acceptability in terms of the needs, issues, and concerns of stakeholder potentially impacted by the project *27.* Failure to effectively consult with stakeholders to determine a level of acceptable risk for tanker, terminal, and pipeline spills *28.* Inadequate assessment and comparison of risks associated with project alternatives	**Not Met**

7. To assess the impact of deficiencies in Enbridge's analysis of tanker spill risk estimates, we undertake additional sensitivity analysis based on the following scenarios:
   a) Combining the four sensitivity parameters that were tested separately by Enbridge (higher scaling factors for grounding, higher ship traffic, extended route, and higher number of tankers)
   b) Using incident frequencies derived from Lloyds Register Fairplay data without the scaling factor adjustments for BC conditions that were done by Enbridge without sufficient documentation or justification
   c) Increasing conditional probabilities by five percentage points
   d) Increasing tanker traffic to transport pipeline throughput of 1,125 kbpd (850 kbpd of oil and 275 kbpd of condensate), which is the design capacity of the ENGP
   e) Increasing tanker traffic associated with replacing very large crude carriers (VLCC) with smaller Suezmax and Aframax tankers to transport throughput of 1,125 kbpd of oil and condensate
   f) Testing the combined effect of all the above parameters.

8. Enbridge did not complete any sensitivity analysis for oil or condensate spills at Kitimat Terminal. To address this deficiency, we undertake a sensitivity analysis for marine terminal operations based on the following scenarios:
   a) Increasing tanker traffic to transport pipeline throughput of 1,125 kbpd (850 kbpd of oil and 275 kbpd of condensate), which is the design capacity of the ENGP
   b) Replacing larger VLCCs with smaller tankers to transport throughput of 1,125 kbpd of oil and condensate that results in an increase in the number of tanker loadings.

9. Enbridge did not complete any sensitivity analysis for oil or condensate spills from the ENGP pipelines. To address this deficiency, we undertake a sensitivity analysis based on the following scenarios:
   a) Using actual spill rates provided by Enbridge for Enbridge's liquids pipeline system for the years 2002-2010
   b) Using spill rates from the NEB for pipebody and operational leaks exceeding 1.5 m^3 or 9 barrels (bbl).

10. Table ES-2 summarizes the impacts of the sensitivity analyses. The results provide a range of possible spill rates for the ENGP and show that the impact of the alternative scenarios on spill rates is significant:
    - The tanker spill return period is between 23 and 196 years, well below Enbridge's mitigated tanker spill estimate of 250 years. This lower estimate of 23 to 196 years still underestimates spill risk because it does not correct for all the deficiencies in Enbridge's spill risk methodology such as underreporting of incidents.
    - The terminal spill return period is between 15 and 41 years compared to Enbridge's estimate of 62 years.
    - The pipeline spill return period of 0.1 years (between 15 and 16 spills per year) based on the actual spill rate experienced on the Enbridge liquids pipeline system from 2002 to 2010 is 31 times higher than the 2 year return period estimated by Enbridge.

These findings show that the deficiencies in Enbridge's analysis result in an underestimate of spill risk.

Table ES-2: Spill Type and Sensitivity Analysis for ENGP Tanker, Terminal, and Pipeline Spills

Type (Oil or Condensate)	**Enbridge Estimate** (Return period in years)	**Adjusted Sensitivity** (Return period in years)
Tanker Spill	250	23 - 196
Terminal Spill	62	15 - 41
Pipeline Spill	2	0.1 - 1

Note: Return periods estimated by Enbridge and used in the adjusted sensitivity analysis represent any size tanker or terminal spill (average spill size of 56,700 bbl and 1,575 bbl, respectively). For pipeline spills, Enbridge estimates return periods using different datasets including reportable spill data from the US PHMSA that represents liquid releases of 5 bbl or more (Enbridge uses average spill size of 594 bbl). The adjusted sensitivity analysis estimates return periods based on: (1) Reportable spills on the Enbridge liquids pipeline system (average spill size of 162 bbl), and; (2) NEB pipeline spill data for leaks greater than 9 bbl.

11. An alternative methodology for estimating spill risk is the United States (US) Oil Spill Risk Analysis (OSRA) model. The OSRA model was developed in 1975 by the United States Department of the Interior and is the model that the US government uses to estimate oil spill likelihood. The OSRA model has been subject to extensive evaluation and improvements since its development and was recently updated in 2012. Despite its widespread use, the OSRA model is not used or referenced by Enbridge. Enbridge provides no justification for not using the OSRA model.

12. Applying the OSRA model results in probability estimates of one or more tanker spills over 1,000 bbl of 95.3% to 99.9% (Table ES-3). The OSRA estimates the probability of one or more tanker spills over 10,000 bbl at 65.1% to 98.2%. Based on planned shipment volumes, the OSRA model estimates oil/condensate spill return periods of 5 to 12 years for spills over 1,000 bbl, between 20 and 50 times more frequent than the Enbridge estimate of 250 years. The OSRA model estimates oil/condensate spill return periods of between 3 and 8 years using the higher volumes based on the ENGP expansion capacity.

Table ES-3: Spill Probabilities for ENGP Tanker Operations Based on OSRA Model

OSRA Model	**Tanker Spill Size**	**Return Period** (in years)	**Spill Probability over 50 years** (%)
Planned Capacity	Oil spill ≥ 1,000 bbl	7 - 17	95.3 - 99.9
	Oil/Condensate spill ≥ 1,000 bbl	5 - 12	98.5 - 99.9
	Oil spill ≥ 10,000 bbl	13 - 48	65.1 - 98.2
	Oil/Condensate spill ≥ 10,000 bbl	10 - 35	76.3 - 99.6
Expansion Capacity	Oil spill ≥ 1,000 bbl	4 - 11	99.3 - 99.9
	Oil/Condensate spill ≥ 1,000 bbl	3 - 8	99.9
	Oil spill ≥ 10,000 bbl	8 - 30	81.8 - 99.9
	Oil/Condensate spill ≥ 10,000 bbl	6 - 23	89.5 - 99.9

Note: Planned capacity represents 525 kbpd of oil and 193 kbpd of condensate; Expansion capacity represents 850 kbpd of oil and 275 kbpd of condensate. The range in results of the OSRA model is based on the differences in years used for calculating spill rates. The high end of the probability range (low end of the return period) is based on the years 1974 to 2008 and the low end of the probability range (high end of the return period) is based on the years 1994 to 2008. The reduced risk based on the 1994 to 2008 period reflects improvements in safety mitigation and is likely more indicative of future spill rates.

13. The conclusions of this report are as follows:

I. *The ENGP Application Contains Major Deficiencies that Underestimate Spill Likelihood*

Enbridge's spill risk analysis contains 28 major deficiencies. As a result of these deficiencies, Enbridge underestimates the risk of the ENGP. Some of the key deficiencies include:

- Failure to present the probabilities of spills over the operating life of the ENGP
- Failure to evaluate spill risks outside the narrowly defined BC study area
- Reliance on LRFP data that underreport tanker incidents by between 38 and 96%.
- Failure to include the expansion capacity shipment volumes in the analysis
- Failure to provide confidence ranges of the estimates
- Failure to provide adequate sensitivity analysis
- Failure to justify the impact of proposed mitigation measures on spill likelihood
- Potential double counting of mitigation measures
- Failure to provide an overall estimate of spill likelihood for the entire ENGP
- Failure to disclose information and data supporting key assumptions that were used to reduce spill risk estimates
- Failure to use other well accepted risk models such as the US OSRA model.

II. *Deficiencies in the ENGP Application Fail to Address the CEAA Decision Criterion*

Due to deficiencies in the oil spill risk assessment, Enbridge does not provide an accurate assessment of the likelihood of significant adverse environmental impacts as required under *CEAA*. Enbridge expresses the likelihood of a spill as return periods for separate components of the project (tanker, terminal, and pipeline) rather than the probability of a spill over the life of the project. Without estimates of the probability of a spill over the operating life of the project, decision makers are unable to determine whether the project meets the *CEAA* criterion of likelihood of adverse environmental effects. Furthermore, due to the deficiencies in the spill risk methodology, Enbridge fails to adequately disclose the extent of risk associated with the ENGP and the uncertainty in estimating risk.

III. *Restating Enbridge's Own Findings as Probabilities Over Project Life Shows that Spill Likelihood is High*

When findings in the ENGP application are restated as the probability of a spill over the operational life of the ENGP instead of return periods, the conclusion based on Enbridge's own analysis is that the likelihood of a spill is high (Table ES-4). These spill probabilities based on Enbridge's analysis underestimate spill likelihood because they are based on methodological deficiencies.

Table ES-4: Probabilities for ENGP Tanker, Terminal, and Pipeline Spills (50 Years)

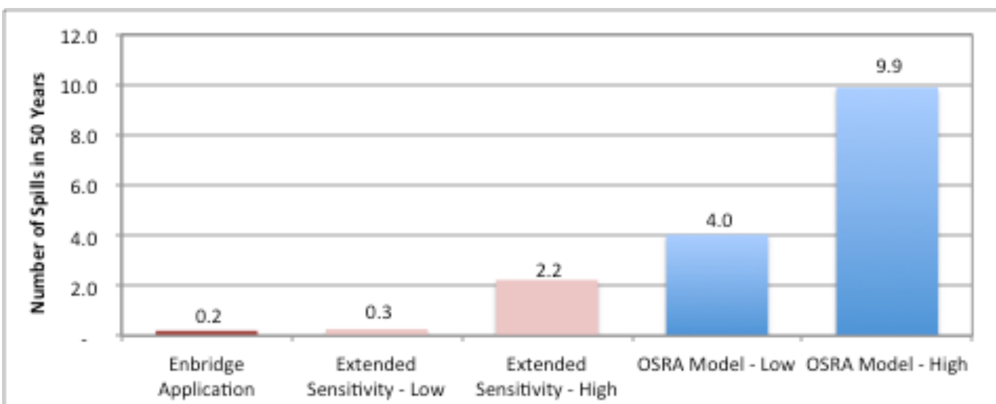
Spill Type (Oil or Condensate)	**Spill Probability over 50 years** (%)
Tanker Spill	18.2
Terminal Spill	55.6
Pipeline Spill	99.9
Combined Spills	99.9

IV. *Sensitivity Analysis Shows that the Likelihood of a Spill is High*

The extended sensitivity analysis for the ENGP demonstrates that there is a higher likelihood of spill occurrence than reported in the ENGP application. For tanker spills, the extended sensitivity analysis evaluates changes to key input parameters such as increasing shipments to the ENGP design capacity and combining parameter changes.

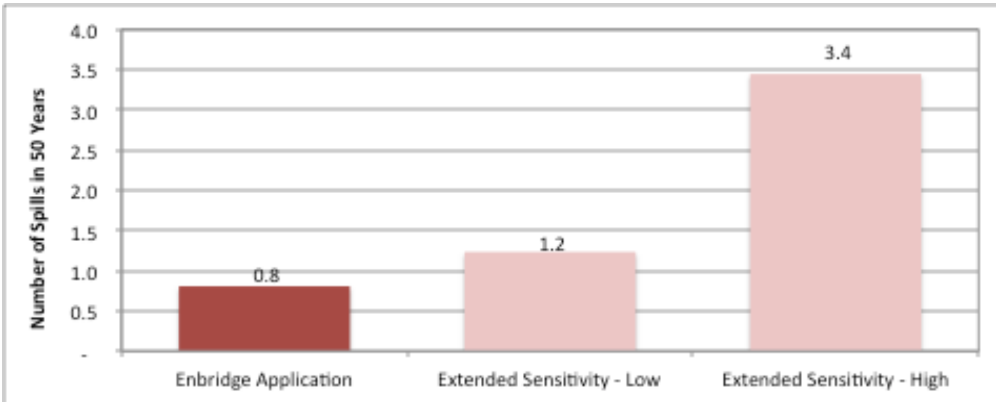
a. The extended sensitivity analysis shows that based on Enbridge's own data, the rate of tanker spills could range between 0.3 and 2.2 spills over a 50-year period, much higher than Enbridge's estimate of less than one spill (Figure ES-1). This range still understates spill risk because it does not correct for all the deficiencies in Enbridge's methodology.

Figure ES-1: Number of ENGP Tanker Spills in 50 Years (Oil and Condensate)



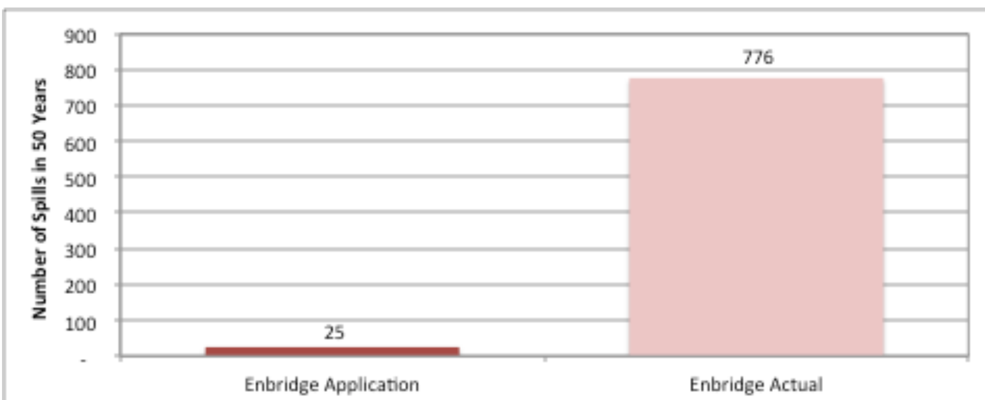
b. The extended sensitivity analysis for terminal spills determines that the rate of spills in a 50-year period could range between 1.2 and 3.4 spills for any size terminal spill, significantly higher than Enbridge's estimate of less than one spill in 50 years (Figure ES-2).

Figure ES-2: Number of ENGP Terminal Spills in 50 Years (Oil and Condensate)



c. The extended sensitivity analysis using spill frequency data from Enbridge's liquid pipeline system results in an estimated 776 oil and condensate pipeline spills in 50 years (or between 15 to 16 spills per year), which is 31 times more frequent than Enbridge's estimate of 25 spills in 50 years (Figure ES-3).

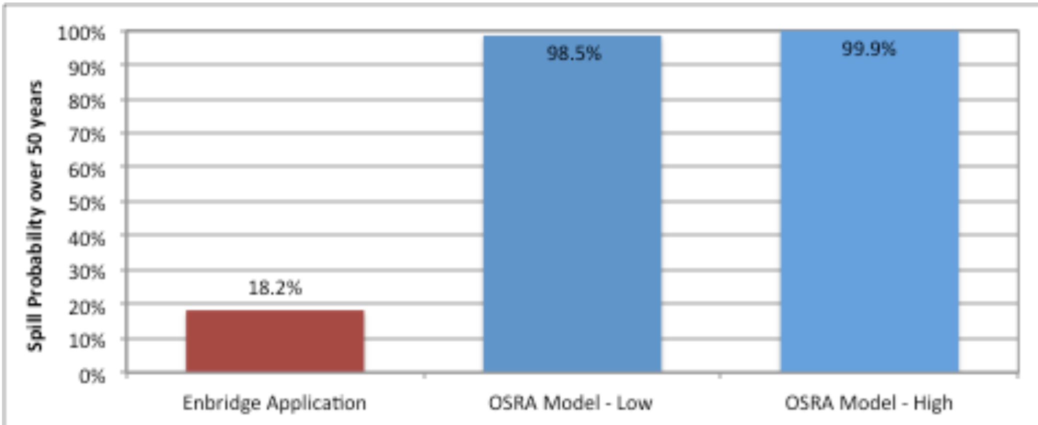
Figure ES-3: Number of ENGP Pipeline Spills in 50 Years (Oil and Condensate)



V. *The OSRA Model Shows the Probability of a Major Spill is High*

The OSRA model is the model the US government uses to estimate spill risk. The OSRA model estimates 4 to 10 tanker spills over 1,000 bbl (159 m^3) could occur in a 50-year period (Figure ES-1), which is 20 to 50 times more frequent than Enbridge's estimate. Due to mitigation measures, the lower end of the OSRA spill range is more likely a better indicator of future risk. In terms of spill probability, the OSRA model estimates that an oil/condensate tanker spill ≥ 1,000 bbl has a 98.5% to 99.9% chance of occurring over a 50-year operating period, well above Enbridge's estimate of 18.2% (Figure ES-4). The lower estimate of 98.5% is likely a better indication of future spill risk due to mitigation measures. The probability of a tanker spill increases to 99.9% if the volume of oil and condensate handled increases to the ENGP expansion capacity of 1,125 kbpd.

Figure ES-4: Probabilities for ENGP Tanker Spills over 50 Years (Oil or Condensate)



VI. *Other Considerations*

Finally, two important considerations must be reconciled in the ENGP regulatory application: risk acceptability to stakeholders, and viable alternatives to the ENGP that reduce risk. Risk acceptability in the ENGP application relies on a technical definition of risk. Acceptable risk however is a value judgment that should be based on the definition of risk as defined by impacted stakeholders. Stakeholders' definition of acceptable risk therefore needs to be assessed and used in the ENGP decision. Second, Enbridge has not identified nor compared viable alternatives that meet the stated purpose of the ENGP. There are viable alternatives to shipping crude oil from the Western Canada Sedimentary Basin to market that involve no risk from oil tanker spills and thus risk from tanker spills can be eliminated. These alternatives should be evaluated relative to the ENGP to assess the most cost effective transportation option.

VII. *Overall Conclusion*

We acknowledge that estimating risk is challenging due to the many uncertainties involved and that different assumptions and methodologies will produce different assessments of risk. The key in risk assessment is to test a range of assumptions and methodological approaches to provide a clear and accurate assessment of the range of likely outcomes so that decision makers can fully judge risk. The conclusion of this report is that Enbridge's oil spill risk assessment contains methodological deficiencies and does not therefore provide an accurate assessment of the degree of risk associated with the ENGP. The risk assessment in this report also concludes that the ENGP has a very high likelihood of a spill that may have significant adverse environmental effects.

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List of Equations, Figures and Tables

List of Acronyms

AB	Alberta
Bbbl	Billion Barrels
bbl	Barrels
BC	British Columbia
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CEAA	*Canadian Environmental Assessment Act*
Dilbit	Diluted Bitumen
DNV	Det Norske Veritas
ENGP	Enbridge Northern Gateway Project
kbpd	Thousand Barrels per Day
km	Kilometres
LRFP	Lloyds Register Fairplay
NEB	National Energy Board
nm	Nautical Miles
OSRA	Oil Spill Risk Analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration
QRA	Quantitative Risk Analysis
US	United States
VLCC	Very Large Crude Carrier

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1. Introduction

This report provides a review of spill estimates for tanker, terminal, and pipeline operations associated with the Enbridge Northern Gateway Project (ENGP). The objective of the report is to assess whether the ENGP is likely to cause significant adverse environmental effects as defined by the *Canadian Environmental Assessment Act* (*CEAA*). According to the *CEAA* the decision maker must decide if the project:

> (a) is **likely** to cause significant adverse environmental effects referred to in subsection 5(1); and
> (b) is **likely** to cause significant adverse environmental effects referred to in subsection 5(2) [emphasis added] (*CEAA* Sec. 52).

Thus a key criterion in the decision of whether or not to approve a project is the likelihood that the project will cause significant adverse environmental effects. In the case of the ENGP, a fundamental component of determining the likelihood that a project will cause significant adverse environmental effects is an assessment of the probability that a spill will occur.

This report assesses the methodologies used to estimate spill probabilities in the ENGP regulatory application. The study uses the following approach to achieve our research objective:

I. Summarize spill estimates submitted by Enbridge for the ENGP
II. Evaluate the marine and terrestrial spill estimates submitted by Enbridge for the ENGP against international best practices criteria
III. Undertake sensitivity analysis to test the impact of deficiencies on the spill rate estimates
IV. Apply the United States (US) Oil Spill Risk Analysis (OSRA) model to estimate marine and terrestrial spill probabilities for the ENGP
V. Submit a draft report summarizing the findings for review by international risk assessment experts and revise report based on the review.

Following the introduction, the second section of our report summarizes the Northern Gateway Project. The third section summarizes Enbridge's estimate of the likelihood of tanker, terminal, and pipeline spills. In the fourth section, we evaluate Enbridge's spill estimate methodology and complete a sensitivity analysis to illustrate the range of spill rates under different scenarios. In the sixth section, we estimate alternative spill probabilities for tanker and pipeline operations using the US OSRA model. The seventh section compares the methodological approach and results of the OSRA model to those submitted as part of the ENGP regulatory application and section eight provides conclusions based on our findings.

It is important to note that the *CEAA* evaluation criterion requires assessment of two components to define risk: the magnitude of an adverse impact and the likelihood of an adverse impact occurring. This report focuses on evaluating only the one component of risk: the likelihood of an adverse impact (oil spills) occurring. Another report completed by Gunton and Broadbent (2012b) addresses the magnitude of the impact of an oil spill and concludes that oil spills as small as 238 m^3 could have significant adverse environmental impacts. The Gunton and Broadbent (2012b) report also concludes that Enbridge's analysis of the magnitude of impacts of oil spills is deficient.

2. The Enbridge Northern Gateway Project

The following section provides a brief overview of tanker traffic, marine terminal, and pipeline operations associated with the ENGP.

2.1. Tanker Traffic Accessing Kitimat Terminal

Tankers accessing Kitimat would include oil tankers exporting crude oil to international markets and condensate tankers importing condensate from abroad. Table 1 provides a breakdown of characteristics for very large crude carriers (VLCC), Suezmax, and Aframax tankers that would transport oil and condensate to and from the marine terminal. The ENGP application forecasts an additional 190 to 250 tankers a year, or an average of 220 vessels, to existing commercial marine traffic accessing Kitimat (Enbridge 2010b Vol. 8B p. 2-9). Tanker traffic of 220 vessels equates to 440 tanker sailings or approximately 8 tanker transits every week. Of the 220 tankers per year forecast to call at the proposed Kitimat Terminal, approximately 149 tankers would export crude oil and 71 tankers would import condensate (Brandsæter and Hoffman 2010). Tankers importing condensate would be laden inbound, while tankers exporting crude oil would be laden for outbound transits. The proposed project has capacity to increase shipments from 525 thousand barrels per day (kbpd) of oil (83,400 m^3 per day) to 850 kbpd and increase the condensate pipeline from 193 kbpd (30,700 m^3 per day) to 275 kbpd with additional pumping capacity (Enbridge 2010b Information Request No. 3). The increased shipments would increase tanker traffic from 220 to 331 per year[1]. Enbridge does not include an assessment of the impact of this higher tanker traffic on spill risk in its analysis.

Table 1: Characteristics of Oil and Condensate Tankers Accessing Kitimat Terminal

Characteristic	Tanker Class		
	VLCC	Suezmax	Aframax
Maximum Deadweight Tonnage	320,000	160,000	81,000
Overall Length (m)	343.7	274.0	220.8
Average Cargo Capacity (m^3)	330,000	160,000	110,000
Average Number of Vessels per Year	50	120	50

Source: Enbridge (2010b).

[1] Estimated based on the increase in tanker traffic according to tanker data and information provided by Brandsæter and Hoffman (2010) in the marine shipping QRA and Dudding (2013)

Enbridge expects that tankers calling at Kitimat Terminal would be chartered, or owned by independent tanker operators, and not owned or operated by Enbridge (Enbridge 2010b Vol. 8A p. 4-3). Owners of chartered tankers bear the responsibility for tanker safety. According to Enbridge (2010b Vol. 8B p. 2-5), operational protocols for tankers include local pilots, escort and tethered tugs, tankers equipped with navigation systems, and the use of radar systems. Enbridge states that it would require all chartered tankers for the ENGP to be double-hulled (Enbridge 2010b Vol. 8A p. 4-84).

Tanker traffic accessing the marine terminal at Kitimat would use three potential routes within an area referred to as the British Columbia (BC) study area. The BC study area includes an open water area defined as marine waters from the Alaskan border to the northern end of Vancouver Island, and from the 12 nautical mile (nm) limit of the Territorial Sea of Canada landward to the northern fjords, as well as a confined channel assessment area defined as the Kitimat Arm, Douglas Channel and channels leading from Douglas Channel to open waters of Queen Charlotte Sound and Hecate Strait. The three tanker routes include a Northern Approach and two Southern Approaches (Figure 1). The Northern Approach is a 251 nm route that approaches north of Haida Gwaii, continues through Hecate Strait and Wright Sound and enters Douglas Channel on its way to Kitimat Terminal. The 190 nm Southern Approach passes directly through Caamano Sound passage through Queen Charlotte Sound, through Hecate Strait and Wright Sound and into Douglas Channel. Finally, the Southern Approach via Principe Channel is a 259 nm route that enters Principe Channel north of Banks Island, through Nepean Sound and Otter Channel, and follows a similar route as the other Southern route into Kitimat Terminal. The three tanker routes will traverse the Pacific North Coast Integrated Management Area and traditional territories of Coastal First Nations.

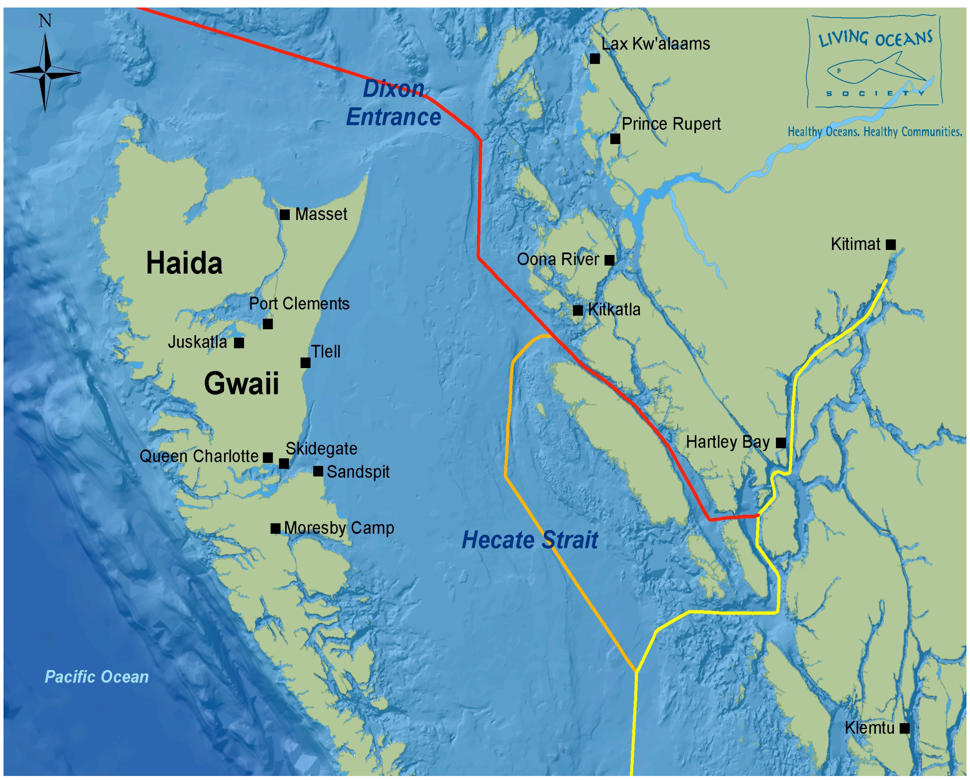
In March 2013, Transport Canada announced amendments to the *Canada Shipping Act* in an attempt to strengthen Canada's tanker safety system. The eight new measures to the tanker safety program include:

- Conduct annual tanker inspections to ensure that foreign vessels comply with rules and regulations
- Expand the aerial surveillance and monitoring of ships
- Establish a Canadian Coast Guard Incident Command System to respond to incidents
- Review current pilotage and tug escort requirements
- Designate more public ports, particularly Kitimat
- Conduct scientific research on petroleum products
- Ensure the installation and maintenance of aids to navigation such as buoys and lights
- Develop options to enhance current navigation system (TC 2013).

Only one of the eight measures, namely annual tanker inspections, represents an actionable preventative measure to reduce the likelihood of a spill and inspections are presently carried out on a regular basis. The existing marine safety framework in Canada consists of Transport Canada regulations and standards under the *Canada*

Shipping Act as well as international regulations from the International Maritime Organization. Transport Canada's tanker policy requires all foreign tankers to be inspected on their first visit to Canada and at least once per year thereafter (TC 2010). The Canadian tanker inspection policy was implemented following the 1990 Brander-Smith report that was commissioned after the Exxon Valdez oil spill. Canada is also a member of international Port State Control agreements enabled by the International Maritime Organization to ensure that foreign vessels comply with international maritime conventions. Canada is among the 27 signatories of the Paris Memorandum of Understanding since 1994 and is among the 18 signatories of the Tokyo Memorandum of Understanding since 1993, both of which entitle member states to inspect foreign ships entering their waters. Thus tankers entering Canada's territorial waters not only undergo regular inspection in Canada but are also inspected by many other nations that are members of the international tanker inspection regime.

Figure 1: Map of ENGP Tanker Operations



Source: Living Oceans (2011)

2.2. Marine Terminal Operations at Kitimat Terminal

Kitimat Terminal is a proposed 220-hectare marine terminal complex on Kitimat Arm that would consist of a tank terminal and marine terminal. The marine terminal would have two principal functions; (1) receive crude oil from the oil pipeline, transfer it to tanks at the marine terminal and load oil onto tankers, and; (2) unload and transfer condensate from tankers to tanks and into the condensate pipeline (Enbridge 2010b Vol. 3).

Major facilities at Kitimat Terminal would include oil and condensate transfer systems, terminal buildings, and tanker berths. The oil transfer system would include an oil receiving station that will direct oil into storage tanks, 11 oil tanks with a nominal capacity of 496,000 barrels (bbl), or 78,800 m^3, and an oil loading system that consists of loading arms for loading oil into tankers (Enbridge 2010b Vol. 3). The condensate transfer system would receive condensate from tankers and pump it to three tanks with similar capacity characteristics as oil tanks, after which the initiating condensate pump station will direct condensate into the pipeline for transport to Bruderheim Station. Approximately 45 buildings are planned for Kitimat Terminal, including various maintenance and storage buildings, electrical buildings, and pumphouses (Enbridge 2010b Vol. 3). The terminal would also have two tanker berths to transfer oil and condensate into and out of VLCC, Suezmax, and Aframax tankers.

2.3. Crude Oil and Condensate Pipeline

Separate crude oil and condensate pipelines would transport hydrocarbons between Kitimat, BC and Bruderheim, Alberta (AB). The crude oil pipeline would deliver diluted bitumen (dilbit) and synthetic oil in the export pipeline from AB to Kitimat Terminal where it will be loaded onto tankers and shipped to market. The condensate pipeline would import condensate from tankers arriving at Kitimat Terminal and deliver it to AB where condensate will be used for blending with crude oil (Enbridge Vol. 2 p. 1-12).

Construction and operation of the oil and condensate pipelines would consist of 1,172 kilometres (km) of pipe, seven pump stations for the oil pipeline, nine pump stations for the condensate pipeline, and Bruderheim Station that would house an initiating oil pump station and condensate receiving facilities (Enbridge 2010b Vol. 3). The crude oil pipeline is designed for an initial average annual throughput of 525 kbpd of oil (83,400 m^3 per day) with potential to expand to 850 kbpd with additional pumping capacity and the condensate pipeline is designed for an initial average annual throughput of 193 kbpd (30,700 m^3 per day) with potential to expand to 275 kbpd (Enbridge 2010b Information Request No. 3). The pipelines will traverse several different physiographic regions including plains, plateaus, and mountains and will cross 773 watercourses, 669 of which are fish-bearing (Enbridge 2010b Vol. 3). The traditional territories of approximately 50 First Nations are along the pipeline route (Hoekstra 2012).

3. Summary of Methodology and Spill Estimates for the ENGP

The following section provides a brief summary of the methodologies used by Enbridge and its consultants to estimate spill likelihood for ENGP tanker, terminal, and pipeline spills (Appendix A contains a more detailed summary). Methodologies and spill estimates in the ENGP regulatory application provide context for the evaluation in section four.

Separate quantitative analyses estimating return periods[2] for tanker, terminal, and pipeline spills were prepared for the ENGP regulatory application. Enbridge contracted Det Norske Veritas (DNV) to prepare the Technical Data Report entitled *Marine Shipping Quantitative Risk Analysis* (marine shipping QRA) that examines tanker and terminal spills in the BC study area and spills at the marine terminal in Kitimat (Brandsæter and Hoffman 2010). Furthermore, Enbridge prepared the risk analysis for pipeline spills between Kitimat, BC and Bruderheim, AB (Enbridge 2010b Vol. 7B) included in *Volume 7B: Risk Assessment and Management of Spills - Pipelines*. An information request from the Joint Review Panel resulted in additional reports submitted in May 2012 evaluating risks associated with Kitimat Terminal (Bercha Group 2012a), public safety in populated areas along the pipeline route (Bercha Group 2012b), pipeline pump stations (Bercha Group 2012c), and pipeline leaks and ruptures (WorleyParsons 2012). The summary of spill estimates for the ENGP in this section largely relies on the following documents submitted as part of the ENGP regulatory application:

- *Volume 7B: Risk Assessment and Management of Spills - Pipelines*
- *Volume 7C: Risk Assessment and Management of Spills - Kitimat Terminal*
- *Volume 8C: Risk Assessment and Management of Spills - Marine Transportation*
- *TERMPOL Study No. 3.15: General Risk Analysis and Intended Methods of Reducing Risk*
- *Marine Shipping Quantitative Risk Analysis* by Det Norske Veritas
- *Northern Gateway Pipeline Kitimat Terminal Quantitative Risk Analysis* by Bercha Group
- *Northern Gateway Pipeline Public Safety Quantitative Risk Analysis* by Bercha Group
- *Northern Gateway Pipeline Pump Station Quantitative Risk Analysis* by Bercha Group
- *Semi-Quantitative Risk Assessment* by WorleyParsons.

3.1. Spills from Tanker Traffic Accessing Kitimat Terminal

DNV determines spill return periods for tanker traffic accessing Kitimat Terminal in the *Marine Shipping Quantitative Risk Analysis*. DNV uses a per-voyage methodology to forecast spills in the marine shipping QRA based on nautical miles (nm) travelled by tankers within the study area. As part of the per-voyage methodology, DNV determines base incident frequencies from historical tanker incident data from Lloyds Register Fairplay (LRFP) for the period 1990-2006 (Brandsæter and Hoffman 2010 p. 5-49). The LRFP data likely reflects tankers operating in jurisdictions where mitigation measures such as escort tugs and marine safety measures such as those announced by the government of Canada are already in use. However, a lack of transparency in the marine QRA prevents verification of the LRFP data.

DNV then calculates incident data for the BC study area by multiplying the international frequency data from LRFP by scaling factors that compare risks in the study area to the international areas on which the incident data are based. The comparison uses 1.0 as a baseline and thus a scaling factor equal to 1.0 suggests that the local conditions

[2] DNV defines a return period as the number of years between spill events (Brandsæter and Hoffman 2010 p. 7-94).

affecting risk are equal to the world average (Brandsæter and Hoffman 2010 p. 5-52). DNV uses a range of scaling factors including the number of course changes, use of pilots with local knowledge, and the distance from ship to shore, among others. Table 2 presents base LRFP incident frequencies and the range of local scaling factors for each incident type.

Table 2: LRFP Base Incident Frequencies and Local Scaling Factors for Incidents in BC Study Area

Tanker Incident Type	**Base LRFP Incident Frequency** (per nm)	**Range of Total Scaling Factors**
Powered Grounding	5.98E-07	0.001 - 1.94
Drift Grounding	9.96E-08	0.01 - 1.56
Collision	4.54E-07	0.01 - 0.54
Foundering	5.04E-10	0.01 - 1.50
Fire/Explosion	3.26E-08	n/a

Source: Brandsæter and Hoffman (2010).

DNV then determines the probability of a spill resulting from a tanker incident by using two different methods to estimate conditional spill probabilities. The first method (Method 1) determines conditional spill probabilities based on LFRP data. According to Brandsæter and Hoffman (2010), LRFP categorizes damages for the four incident types into minor damage, major damage, and total loss and LRFP provides a frequency distribution for each damage category. The second method (Method 2) estimates spill quantities for bottom and side damages based on information from the International Marine Organization International Convention for the Prevention of Pollution from Ships (MARPOL) and estimates spill size distribution with Naval Architecture Package software. Table 3 compares conditional spill probabilities from Methods 1 and 2 and shows the mean oil outflow for grounding and collision incidents estimated with Method 2.

Table 3: Conditional Spill Probabilities for Tanker Incidents (Method 1 and Method 2)

Incident Type	**Conditional Spill Probability** (%)				
	Method 1		**Method 2**		
	Laden	**Ballast**	**Laden**	**Ballast**	**Mean Oil Outflow*** (m^3)
Grounding	32.7	6.4	17.5 - 18.7	< 0.1 - 0.2	736 - 1,725
Collision	19.1	2.6	21.0 - 27.7	5.7 - 14.2	638 - 1,399
Foundering	100	100	n/a		n/a
Fire/Explosion	27.0	7.6	n/a		n/a

Source: Brandsæter and Hoffman (2010)
* Mean oil outflow represents outflow from laden vessels (not vessels in ballast)

In addition to determining spill probabilities for various tanker sizes and oil outflows, Method 2 also estimates probabilities for grounding and collision spills exceeding a certain volume. According to the Monte Carlo simulation, the probability of a spill greater than 10,000 m^3 for a laden VLCC grounding is 5.5% and 25% for a collision (Brandsæter and Hoffman 2010 p. 6-81 - 6-85). The probability of a grounding spill exceeding 25,000 m^3 and 40,000 m^3 is 1% and 0.2%, respectively, while the probability of a collision spill exceeding 20,000 m^3 and 50,000 m^3 is 10% and 0.3%, respectively (Brandsæter and Hoffman 2010 p. 6-81 - 6-85).

DNV estimates unmitigated spill return periods for each type of tanker incident based on scaled incident frequencies, conditional probabilities, the length of each segment, and the number of times the route is travelled per year. DNV presents unmitigated risk as a return period, which is the number of years between spill events, and is an alternative to stating the annual probability of a spill. According to DNV, an unmitigated tanker incident will result in an oil/condensate spill once every 78 years (see Table 6). DNV also estimates unmitigated return periods for various oil spill sizes and, based on Method 2 of the consequence assessment, DNV estimates that a spill exceeding 5,000 m^3 will occur every 200 years while a spill exceeding 40,000 m^3, will occur every 12,000 years (see Table 7).

DNV conducts a sensitivity analysis in its marine shipping QRA examining impacts of several parameters on spill probabilities. The sensitivity analysis tests the impact of changes in parameters on all three potential routes separately under the assumption that all 220 tankers forecast to call at Kitimat Terminal use the route being tested exclusively. Therefore, the spill probabilities do not account for using a combination of routes. Results from the sensitivity analysis suggest that return periods change modestly compared to baseline return periods (Table 4).

Table 4: Summary of Sensitivity Analysis on Spill Return Periods (years)

Sensitivity Parameter	North Route	South Route via Caamano Sound	South Route via Browning Entrance
Baseline	**69**	**83**	**84**
Sensitivity 1: Increase in Scaling Factors for Grounding	59	71	71
Sensitivity 2: Increase in Traffic Density for Collisions	67	81	82
Sensitivity 3a: Decrease to 190 Tankers per year	80	96	97
Sensitivity 3b: Increase to 250 Tankers per year	61	73	74
Sensitivity 4: 200 nm Extension to Segments 5 and 8*	67	81	82

* DNV does not provide overall return periods for the trip extension sensitivity analysis and thus return periods were calculated based on Brandsæter and Hoffman (2010).

The next step in the DNV analysis estimates the impact of various mitigation measures on spill return periods. DNV examines several risk reduction measures qualitatively including enhanced navigational aids, vessel traffic management system, environmental limits for safe operation, and the establishment of places of refuge along tanker routes. The marine shipping QRA only quantitatively evaluates a single mitigation measure: the tug escort plan. DNV obtains the risk reducing effect of escort tugs from a confidential study it completed in 2002 and applies the downward adjustments directly to powered grounding, drift grounding, and collision incidents for the ENGP (Table 5).

Table 5: Estimated Reduction in the Frequency of Incidents from Tug Use

Incident type	Condition	Reduction Effect
Powered Grounding	Laden with close and tethered tug	80%
	Laden with close escort	
	Ballast with close escort	
Drift Grounding	Laden with close and tethered tug	90%
	Laden with close escort	80%
	Ballast with close escort	
Collision	Laden or ballast with close and/or tethered escort	5%

Source: Brandsæter and Hoffman (2010 p. 8-120).

Table 6 compares mitigated return periods to unmitigated return periods for oil or condensate spills. For all tanker spills, mitigation measures increase the spill return period from 78 years to 250 years. Mitigation measures for powered and drift grounding increase return periods by three- and four-fold, respectively.

Table 6: Comparison of Unmitigated and Mitigated Oil/Condensate Spill Return Periods

Incident Type	Unmitigated Return Period (in years)	Mitigated Return Period (in years)
Powered Grounding*	107	480
Drift Grounding*	535	2,758
Collision*	1,084	1,138
Foundering*	25,821	25,821
Fire/ Explosion*	1,838	1,838
Total	**78**	**250**

Source: Brandsæter and Hoffman (2010).
* Calculated based on Brandsæter and Hoffman (2010).
Note: DNV does not identify mitigation measures for foundering and fire/explosion spills.

DNV also estimates the impact of mitigation measures on return periods by size of the spill. As shown in Table 7, the use of tugs increases return periods from 200 to 550 years for an oil spill greater than 5,000 m^3.

Table 7: Comparison of Unmitigated and Mitigated Return Periods for Various Oil Spill Sizes

Spill Volume (m^3)	Unmitigated Return Period (in years)	Mitigated Return Period (in years)
> 5,000	200	550
> 20,000	1,750	2,800
> 40,000	12,000	15,000

Source: Brandsæter and Hoffman (2010 p. 7-110; 137).

3.2. Spills from Operations at Kitimat Terminal

DNV determines spill return periods for particular types of incidents at Kitimat Terminal in the *Marine Shipping Quantitative Risk Analysis*. Furthermore, the Bercha Group estimates risks from spills to the public and workers at the terminal in the *Northern Gateway Kitimat Terminal Quantitative Risk Analysis*.

In its risk analysis, DNV determines incident frequencies for berthing/deberthing and cargo transfer operations at the marine terminal based on LRFP data and DNV's research of operating terminals in Norway. DNV examines four types of potential incidents at the marine terminal and determines that spills associated with cargo transfer operations pose the greatest spill risk (Table 8). Although Brandsæter and Hoffman (2010) acknowledge that there is some risk of either a tanker striking the pier during berthing or a passing vessel impacting a tanker, these incidents are not included in the unmitigated return periods for terminal spills.

Table 8: Incidents Types Examined for Marine Terminal Spills

Terminal Incident Type	Spill Likelihood	Description
Tanker Impacted by Tug	n/a	Harbour tugs will not achieve the speeds necessary to penetrate tanker hulls
Tanker Strikes Pier During Berthing	Low	Energy produced from pier impact is not sufficient to penetrate tanker hull
Tanker Impacted by Passing Vessel	Low	Risk is low due to low volume of vessel traffic passing Kitimat Terminal
Cargo Transfer Operations	Various	Spill risk depends on the type of transfer operation failure

Source: Brandsæter and Hoffman (2010)

Probabilities and distribution of cargo released per loading/discharging operation are summarized in Table 9. DNV develops a spill size distribution for each event type from a review of historical databases from Norway and the UK and categorizes spill sizes according to the International Tanker Owners Pollution Federation Limited[3] (Brandsæter and Hoffman 2010 p. 6-91).

Table 9: Spill Probability and Spill Size Distribution for Cargo Transfer Operations

Event Type	Probability of Spill (per operation)	Distribution of Spill Size	
		Small (< 10 m³)	Medium (10 – 1,000 m³)
Release from Loading Arm	5.1E-05	90%	10%
Equipment Failure	5.1E-06	0%	100%
Failure in Vessels Piping System or Pumps	7.2E-06	90%	10%
Human Failure	7.2E-06	90%	10%
Mooring Failure	3.8E-06	0%	100%
Overloading of Cargo Tank*	1.2E-04	0%	100%

Source: Brandsæter and Hoffman (2010 p. 5-75) and DNV (2000) *as cited in* Brandsæter and Hoffman (2010 p. 6-92).
Note: Spill Probabilities represent loading and discharge for every event type with the exception of overloading of cargo tank.
* Overloading of cargo tank can only occur during loading operations.

DNV presents unmitigated risk as return periods for spills, which it calculates based on forecast tanker traffic calls to Kitimat Terminal and spill size distributions for particular types of cargo transfer operations. DNV estimates that unmitigated small or

[3] According to Brandsæter and Hoffman (2010 p. 6-91), the International Tanker Owners Pollution Federation Limited categorizes spills as follows: small spills (<7 tonnes ~ 10m³); medium spills (7-700 tonnes ~ 10-1,000m³); large spills (>700 tonnes ~ 1,000m³).

medium size oil/condensate spills from cargo transfer operations will occur once every 29 years (see Table 10).

DNV applies mitigation measures to its unmitigated risk evaluation and recalculates return periods for spills at the marine terminal. DNV quantitatively evaluates a closed loading system with vapour recovery as the principal mitigation measure for spills at the marine terminal. DNV claims that the closed loading system and vapour recovery unit will eliminate any risk of an oil spill associated with overloading cargo tanks and thus the probability per year of this event occurring drops to zero (Brandsæter and Hoffman 2010 p. 131). According to DNV, mitigation measures more than double the return period for unmitigated oil/condensate spills from 29 to 62 years (Table 10).

Table 10: Comparison of Overall Unmitigated and Mitigated Oil/Condensate Spill Return Periods for Cargo Transfer Operations

Cargo Transfer Operation	Unmitigated Return Period (in years)	Mitigated Return Period (in years)
Release from Loading Arm	89	89
Equipment Failure	891	891
Failure in Vessels Piping System or Pumps	631	631
Human Failure	631	631
Mooring Failure	1,196	1,196
Overloading of Cargo Tank*	56	n/a
Total	**29**	**62**

Source: Brandsæter and Hoffman (2010).

The Bercha Group (2012a) prepared a risk analysis examining spills associated with operations at the marine terminal. The risk assessment examines worker and public safety at the marine terminal measured according to the risk to individuals exposed to oil or condensate releases (Bercha Group 2012a). The Bercha Group examines failure frequencies that include the following terminal components: piping, pumps, storage tanks, and loading/unloading arms (Bercha Group 2012a). Based on calculations from the Bercha Group report, the return period for a rupture from one of the terminal components is 282 years (Table 11).

Table 11: Rupture Failure Frequencies for Marine Terminal Components

Component	Rupture Failure Frequency	Estimated Return Period (in years)*
Piping	1.00E-07	10,000,000
Pumps	1.00E-04	10,000
Oil Tanks	5.50E-05	18,182
Condensate Tanks	1.50E-05	66,667
Loading Arm - Oil	2.29E-03	437
Unloading Arm - Condensate	1.09E-03	917
Total*	**3.55E-03**	**282**

Source: Bercha Group (2012a p. 4.4).
* We estimate return periods based on information and data from Bercha Group (2012a).

The Bercha Group (2012a) concludes that risks to individuals from operations at the marine terminal are within tolerable limits. Based on Individual Specific Risks thresholds, the authors determine that risks to the public in the area surrounding the terminal are insignificant at less than one in one million, while risks to workers are higher although tolerable at a range of between one in 10,000 and one in 100,000. The authors recommend mitigation measures to ensure safe operational and work procedures at the marine terminal.

3.3. Spills from Pipeline Operations

The ENGP regulatory application contains several pipeline spill estimates. In its regulatory application submitted in 2010, Enbridge prepared a section in *Volume 7B* estimating return periods for spills that occur along the pipeline route. In 2012, WorleyParsons and the Bercha Group submitted additional risk analyses estimating pipeline spill likelihood for the project.

Volume 7B of the Enbridge application identifies return periods for a hydrocarbon[4] release that occurs along the pipeline route. Enbridge calculates spill return periods with liquid pipeline failure frequency data from 1991 to 2009 from the National Energy Board (NEB). Enbridge notes that NEB data include pipelines up to 50 years old that use older technology and building material standards associated with an increased frequency of failures compared to modern pipelines (Enbridge 2010b Vol. 7B, p. 3-1). Accordingly, Enbridge factored improved design features and mitigation planning characteristic of modern pipelines into its failure frequency calculations and expects improvement factors to decrease the probability of a pipeline failure relative to NEB failure frequency data (Enbridge 2010b Vol. 7B, p. 3-1).

Enbridge estimates return periods for various spill size categories of hydrocarbon releases for six regions along the pipeline route. Enbridge bases spill size categories on NEB classifications whereby a small spill is less than 30 m^3, a medium spill ranges between 30 and 1,000 m^3, and a large spill exceeds 1,000 m^3 (Enbridge 2010b Vol. 7B). Enbridge identifies the six physiographic regions along the pipeline route as the Eastern Alberta Plains, the Southern Alberta Uplands, Alberta Plateau, Rocky Mountains, Interior Plateau, and the Coast Mountains. Table 12 presents spill return periods calculated by Enbridge for medium and large spills in the six regions. Although Enbridge presents spill return periods separately for each region, we combine return periods for medium and large spills for the entire length of the pipeline that results in a return period of 28 years.

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[4] Enbridge (2010b Vol. 7B p. 3-1) refers to pipeline spills as hydrocarbon spills. We interpret hydrocarbon spills to include both oil and condensate and thus assume spill return periods represent oil or condensate spills.

Table 12: Return Periods for Spills from the Northern Gateway Pipeline

Physiographic Region	**Approximate Pipeline Length** (km)	**Spill Return Period** (in years)	
		Medium	**Large**
Eastern Alberta Plains	166	287	669
Southern Alberta Plains	350	136	317
Alberta Plateau	44	1,082	2,525
Rocky Mountains	103	462	1,079
Interior Plateau	404	118	275
Coast Mountains	105	454	1,058
Total*	**1,172**	**41**	**95**
Combined Medium and Large Spills**		**28**	

Source: Based on Enbridge (2010b Vol. 7B p. 3-2).
* We combine spill return periods for each segment to represent the spill return period for the entire pipeline route.
** We combine return periods for medium and large spills into a single return period based on information provided in *Volume 7B* of the ENGP regulatory application.
Note: Medium spills represent spills from 30 to 1,000 m^3 and large spills represent spills > 1,000 m^3.

Enbridge contracted WorleyParsons to prepare a risk assessment entitled *Semi-Quantitative Risk Assessment* to determine spill frequencies for leaks and full-bore pipeline ruptures over the length of the ENGP pipeline[5]. The analysis uses several methodological approaches and datasets including a failure frequency model that uses data from recently constructed pipelines, particularly Enbridge Line 4, as well as pipeline spill data from the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) from 2002 to 2009 (WorleyParsons 2012). The WorleyParsons report identifies eight pipeline hazards and determines that the probability of a 594-bbl (94 m^3) oil pipeline leak is 0.249, which results in a return period of 4 years (Table 13). The WorleyParsons report estimates an annual probability of 0.0042 (return period of 239 years) for a full-bore pipeline rupture releasing 14,099 bbl (2,238 m^3) of oil. In addition to estimating oil spills, WorleyParsons estimates return periods for a 593 bbl (94 m^3) condensate leak of 4 years and a 5,183 bbl (823 m^3) condensate rupture of 273 years.

[5] The WorleyParsons (2012) report focuses on full-bore pipeline ruptures, which according to WorleyParsons, is a pipeline spill that releases hydrocarbons in an unconstrained manner (WorleyParsons 2012 p. 4). The second attachment in the report contains a failure likelihood assessment by Dynamic Risk Assessment Systems that estimates likelihoods for pipeline leaks. For simplicity, we refer to the WorleyParsons report in its entirety including all the report's attachments.

Table 13: Return Periods for Leaks and Full-bore Ruptures

Pipeline Hazard	Return Period (in years)			
	Oil Pipeline		Condensate Pipeline	
	Leak	Rupture	Leak	Rupture
Internal corrosion	0	0	0	0
External corrosion	0	0	0	0
Materials and manufacturing defects	652	652	652	652
Construction defects	39	0	39	0
Equipment failure	5	0	5	0
Incorrect operations	47	0	47	0
Damage from third parties	436	1,308	1,385	4,149
Geotechnical and hydrological threats	0	530	0	530
Total	**4**	**239**	**4**	**273**

Source: WorleyParsons (2012); WorleyParsons (2012 as cited in WrightMansell 2012)

The Bercha Group prepared two risk assessments examining separate risks from pump stations and pipeline ruptures associated with the ENGP pipeline. Both studies use a similar methodological approach that includes determining hazards, assessing the frequency of occurrence of a spill, evaluating spill consequences, assessing risk, and identifying mitigation measures that reduce risk (Bercha Group 2012b; 1012c).

The first Bercha Group (2012c) study assesses worker and public safety risks from an oil or condensate spill at Smoky River Station, the largest pump station along the pipeline route in Alberta near Grande Prairie. Table 14 shows the failure frequencies per year for combined piping and pump spills at the Smoky River Station.

Table 14: Frequencies for Piping and Pump Spills at Smoky River Station

Type of Spill	Failure Frequency (per year)	Return Period (in years)*	Release Volume (m^3)
Oil Leak	3.01E-03	332	50
Oil Rupture	6.02E-04	1,661	1,000
Condensate Leak	1.22E-03	820	50
Condensate Rupture	2.45E-04	4,082	300

Source: Bercha Group (2012c).
* Calculated from Bercha Group (2012c).

The second Bercha Group (2012b) study identifies areas along the pipeline route that are known to have high public concentrations and determines the risk to individuals of a pipeline spill at those locations. The authors identify three heavily populated areas that could be affected by a pipeline spill: A casino near Whitecourt, AB; Burns Lake, BC; and Kitimat, BC.

To determine public risk from a pipeline spill, the Bercha Group (2012b) estimates the failure frequency of the ENGP pipeline based on historical pipeline rupture data from the NEB from 1991 to 2009 and makes several adjustments to the data to incorporate various improvements in pipeline operations. As shown in Table 15, the failure rate of 0.372 per 10,000 km per year (10,000 km-year) based on NEB historical data decreases significantly to 0.109 spills per 10,000 km-year due to numerous downward adjustments ranging from 60 to 90%. The Bercha Group (2012b) concludes that risks to public safety from a pipeline failure near the Casino at Whitecourt, Burns Lake, and Kitimat are insignificant. Risks to residents and indoor and outdoor workers from a pipeline releasing oil, condensate, or both are all below one in one million per year, which the Bercha Group determines are acceptable levels of risk (Bercha Group 2012b).

Table 15: NEB Pipeline Failure Frequencies Adjusted Downward to Represent the ENGP

Pipeline Failure Causes	**NEB Failure Rate** (per 10,000 km-year)	**ENGP Failure Rate** (per 10,000 km-year)	**Downward Adjustment**	**Reason for Adjustment**
Metal Loss	0.085	0.017	80%	Modern piggable pipelines are less likely to fail than pipelines represented in NEB data
Cracking	0.128	0.013	90%	Advanced coating technologies, low stress design, and fatigue avoidance through design and operations
External Interference	0.021	0.021	-	n/a
Geotechnical Failure	0.021	0.021	-	n/a
Material Failure	0.021	0.009	60%	Construction quality control, inspection/testing after construction, and operational surveillance
Other Causes	0.096	0.028	71%	Estimated as same percentage as NEB data (approx. 26%)
Total	**0.372**	**0.109**	**71%**	

Source: Bercha Group (2012b).

3.4. Summary of Tanker, Terminal, and Pipeline Spill Estimates for the ENGP

Table 16 presents a brief summary of spill return periods from the ENGP regulatory application. For tanker spills, return periods range between 78 years for an unmitigated oil or condensate spill of any size to 15,000 years for a mitigated oil spill exceeding 40,000 m^3. Terminal spills range from one unmitigated oil/condensate spill of any size occurring every 29 years to one mitigated spill every 430 years for medium oil spills releasing 10 to 1,000 m^3 of oil. Pipeline spills range from a leak releasing 94 m^3 every 2 years to a full-bore rupture releasing 2,238 m^3 of oil every 239 years. The ENGP regulatory application does not evaluate overall spill likelihood for tanker, terminal, and pipeline spills. If spill return periods are evaluated collectively for the entire ENGP, data from the ENGP application suggest that a tanker or terminal or pipeline spill could occur once every 2 years[6].

[6] Return period calculated based on the following spill probabilities: (1) any size tanker spill; (2) any size terminal spill, and; (3) pipeline leak.

Table 16: Summary of Spill Return Periods for the ENGP

Type of Spill		Return Period (in years)
Tanker Spill		
Any size spill	Oil/Condensate	78 - 250
	Oil	110 - 350
Oil spill exceeding a certain size	> 5,000 m^3	200 - 550
	> 20,000 m^3	1,750 - 2,800
	> 40,000 m^3	12,000 - 15,000
Terminal Spill		
Any size spill	Oil/Condensate	29 - 62
	Oil	34 - 90
Small spill (< 10 m^3)	Oil/Condensate	77
	Oil	110
Medium spill (10 - 1,000 m^3)	Oil/Condensate	46 - 294
	Oil	49 - 430
Pipeline Spill		
Leak (94 m^3)	Oil/Condensate	2
	Oil	4
Rupture#	Oil/Condensate	128
	Oil	239
Tanker, Terminal, or Pipeline Spill		
Spill from ENGP*	Oil/Condensate	2
	Oil	4

Source: Brandsæter and Hoffman (2010); Worley Parsons (2012).
Note: Range represents mitigated and unmitigated spill probabilities with the exception of pipeline spills
* Overall spill probability for ENGP based on spill probabilities for any size tanker spill, any size terminal spill, and pipeline leaks.
# Average size oil pipeline rupture is 2,238 m^3 and average size condensate rupture is 823 m^3 (WorleyParsons 2012).

4. Evaluation of ENGP Spill Estimates

The following section evaluates spill return periods presented in the ENGP regulatory application. The objective of the assessment is to examine whether the methodological approach used by Enbridge and its consultants adequately assesses the likelihood of significant adverse environmental effects as required in the *CEAA.* To achieve this objective, we assess methodologies estimating return periods for tanker, terminal, and pipeline spills in the ENGP application with best practice criteria and identify any deficiencies.

We examined several sets of guidelines for risk assessment practices and principles and synthesized the literature into a single evaluative framework (Table 17). We use the following four-point scale to assess the degree to which each criterion is met:

- Fully met: no deficiencies
- Largely met: no major deficiencies
- Partially met: one major deficiency
- Not met: two or more major deficiencies.

Table 17: Evaluative Criteria for Assessing the Quality of Methodological Approaches to Estimating Risk

Criterion	Description	Source
Transparency	Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk	BC MoELP (2000); US EPA (1998); US EPA (2000); US EPA (2004); IALA (2008)
Replicability	Documentation provides sufficient information to allow individuals other than those who did the original analysis to obtain similar results	US EPA (1998); IALA (2008); NRC (1996)
Clarity	Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision making	US EPA (1998); US EPA (2000); US EPA (2004)
Reasonableness	The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment	BC MoELP (2000); US EPA (1998); US EPA (2000); NRC (1996)
Reliability	Appropriate analytical methods explicitly describe and evaluate sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk	BC MoELP (2000); US EPA (2000); US EPA (2004); NRC (1996)
Validity	Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis	US EPA (2000); US EPA (2004); IALA (2008)
Risk Acceptability	Stakeholders identify and agree on acceptable levels of risk in a participatory, open decision-making process and assess risk relative to alternative means of meeting project objectives	BC MoELP (2000); IALA (2008); NRC (1996)

Transparency

Criterion: Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk.

There are six major deficiencies related to transparency in the methods estimating spill return periods in the ENGP regulatory application. Major deficiencies include:

1. ***Lack of supporting evidence for LRFP tanker incident frequency data***
   The frequency assessment in chapter five of the *Marine Shipping Quantitative Risk Analysis* and described in section 3.1, which is the foundation for estimating return periods for tanker spills, fails to provide the necessary supporting evidence.

   First, there is inadequate information describing the LRFP data that contains grounding, collision, foundering, and fire/explosion incidents. DNV fails to provide proprietary data in an appendix or data file that includes information on the type of accident, location, date, factors contributing to the incident, and whether or not the incident resulted in a spill. Instead, DNV simply states that LRFP data are obtained from 1990 to 2006 "...since the type of vessels in operation and the incidents that have occurred after 1990 are considered to be more representative of modern tanker operations, such as the one planned by Northern Gateway."

(Brandsæter and Hoffman 2010 p. 5-49). This lack of transparency raises concerns related to the number and types of tanker incidents included in the data set and whether the analysts altered any of the LRFP data based on undisclosed assumptions. Further, LRFP data likely reflects jurisdictions where marine safety measures such as those announced by the Canadian government and mitigation measures such as escort tugs are already enforced. Thus incident frequencies potentially double count the use of escort tugs that DNV incorporates into LRFP data to reduce the likelihood of tanker spills although it is impossible to determine without access to the proprietary data (potential double-counting of mitigation measures discussed on p. 33).

Second, DNV fails to support assumptions used in the development of tanker incident frequencies. DNV claims that assumptions used in the development of base incident frequencies per nm are based on information from tanker operators and captains, as well as studies of vessel operating patterns (Brandsæter and Hoffman 2010 p. 5-50) yet there is no evidence provided to support these assumptions. Two of the four assumptions used to estimate the average distance travelled by a tanker per year are supported with reference to a study completed for the liquefied natural gas terminal Rabaska (Rabaska 2004 as cited in Brandsæter and Hoffman 2010 p. 5-51). However, detailed information or discussion comparing the similarities and differences between Rabaska and the ENGP is absent from the report and the Rabaska study is not appended to DNV's study nor is it found in the project's public registry database on the NEB website. Furthermore, assumptions related to the amount of time tankers sail in areas where a grounding could occur and the amount of time tankers sail in open water where foundering can occur are not supported with any evidence or references nor are any of the assumptions calibrated with historical data or expert opinion.

Incident frequencies are the basis for estimating spill return periods in the ENGP application. Since return periods are the product of incident frequencies, conditional probabilities, the distribution of tanker routes travelled, the length of each tanker route, and mitigation measures, any uncertainty or errors in incident frequencies will carry through to the final result. Thus, given the importance of incident frequencies as a critical data input, DNV must effectively disclose all adjustments, assumptions, and uncertainties in a transparent manner. The lack of evidence in the ENGP regulatory application makes it impossible to assess the validity of these values.

2. *Insufficient evidence supporting conditional probabilities for tanker spills*

The consequence assessment portion of the marine shipping QRA fails to adequately disclose any supporting information used to estimate conditional probabilities that an incident will result in a spill. DNV uses two different methods to estimate conditional spill probabilities: the first method determines conditional spill probabilities based on LFRP data; the second method estimates spill quantities for bottom and side damages for groundings and collisions based on the International Marine Organization International Convention for the Prevention of

Pollution from Ships (MARPOL) and Naval Architecture Package software. In the first method, DNV simply claims that conditional spill probabilities are "based on the research of spill to damage data" (Brandsæter and Hoffman 2010 p. 6-79) without providing the dataset from which it estimates conditional spill probabilities. Similarly, DNV does not support conditional probability estimates for various spill volumes in the second method with proprietary data and fails to provide adequate information describing the nature of the original data used in the analysis such as its assumptions, data gaps, and limitations. Similar to incident frequencies, the importance of conditional probabilities as a major data input into DNV's methodological approach requires effective transparency of the data and methods used to calculate conditional probabilities. Yet again, a lack of transparency prevents validation of these important conditional probabilities.

3. ***Limited transparency in the application of local scaling factors to the BC study area***
DNV completed a qualitative assessment to develop local scaling factors for tanker traffic navigating the BC Coast that contains several deficiencies. The information gathering process to determine scaling factors incorporated data obtained from local meetings and interviews with tug boat operators, barge operators, sports fishermen, environmental groups, and terminal operators (Brandsæter and Hoffman 2010 p. 4-46). After scaling factors were developed, a workshop held by DNV and attended by experts in marine risk assessment, tanker operations, and navigation validated the findings (Brandsæter and Hoffman 2010 p. 5-52).

Despite the inclusive approach and the effort to engage local stakeholders, there is a lack of evidence and transparency with how certain judgments for scaling factors were made. DNV assesses local scaling factors against a baseline factor, yet does not provide information on comparative areas used to determine the scaling factor nor does it provide adequate evidence supporting the assigned scaling factor. An example illustrates the subjectivity of scaling factors used to localize incident frequencies. For powered grounding accidents, one of the three scaling factors, *navigational route*, represents the number of course changes and the distance to shore. The 'world average' of 1.0 for the scaling factor *navigational route* describes areas where the "distance to shore or shallow water is approximately 4 nm, and with very few critical course changes" (Brandsæter and Hoffman 2010 p. 5-54). Based on this 'world average', scaling factors for each segment range from 0.001 to 2.1 and ambiguous statements such as "narrow channel and consecutive course changes" or "some navigational challenges and course changes" support scaling factors (Brandsæter and Hoffman 2010 p. 5-55). What exactly is meant by "consecutive course changes" or "some navigational challenges"? What is the difference between assigning a 1.5 for one segment compared to assigning a 1.8 for another segment and what differences in conditions do these different scaling factors describe? Is there a mathematical relationship between scaling factors for different segments? Was there a methodical approach to assigning these values and if so, what were the criteria? What navigational routes are included in the world average? Similar concerns related to subjectivity and ambiguity exist for other scaling factors that adjust powered grounding, drift grounding, collision, foundering, and incidents involving fire or explosion to the BC context.

Furthermore, DNV does not clearly identify whether it assesses scaling factors based on the comparison of the ENGP route to all other routes in the world for which the data is collected or whether it assesses factors for the routes that are close to shore in an area similar to the BC study area. Each approach would produce significantly different estimates that result in material changes to incident frequencies. Consequently, there is no basis on which to assess the validity of the scaling factors.

4. ***Lack of information provided to compare incident frequencies at the proposed Kitimat Terminal to marine terminals in Norway***

DNV does not provide adequate evidence to support its claim that "Incident frequencies from terminals in Norway are most representative of the operation planned for the Kitimat Terminal and should provide an appropriate forecast of the possible incident frequency at the Kitimat Terminal" (Brandsæter and Hoffman 2010 p. 5-71). Given that the organization, DNV Maritime and Oil & Gas, is headquartered in Norway, it seems appropriate that DNV use proprietary research from its country of origin. However, DNV fails to make any comparison of marine terminals in Norway to the proposed terminal in Kitimat. What are the geographic, physical, biological, and socioeconomic similarities between terminals in both regions? What are the differences in regulatory environments and marine safety practices between Canada and Norway? How do historical incident frequencies compare at terminals in Canada and Norway? These questions represent only some of the comparisons that should be made to support DNV's decision to use incident frequencies from Norway to forecast possible incident frequencies at Kitimat Terminal.

5. ***Lack of transparency for mitigation measures that reduce the likelihood of tanker and terminal spills***

The fifth major deficiency concerning transparency relates to mitigation measures and their risk reducing effect on spill return periods. In Chapter 8 of the *Marine Shipping Quantitative Risk Analysis*, DNV examines risk reduction measures for tanker and terminal operations. The evaluation largely consists of a qualitative assessment of the characteristics of tug operations, enhanced navigational aids, and vessel traffic management system, among others. The only quantitative risk reduction factors considered in the methodological approach estimating spill return periods are escort tugs for tankers and a closed loading system at the marine terminal for cargo transfer operations. DNV estimates that both mitigation measures significantly decrease spill return periods.

DNV bases the risk reducing effect of escort and tethered tugs for tanker incidents on a confidential study it completed in 2002 for tug escort operations at Fawley Terminal in the United Kingdom. According to this study, DNV claims that the use of escort and tethered tugs will reduce the frequency of powered and drift grounding events 80% to 90% and will reduce collision incidents 5% (Brandsæter and Hoffman 2010 p. 8-120). DNV determines that the use of escort and tethered tugs will increase return periods from 78 years to 250 years for any size oil or condensate spill thus producing a three-fold risk reduction effect compared to unmitigated return periods. Given the significant increase in return periods forecast to occur with the use of escort and tethered tugs for tanker traffic, it is important for DNV to transparently provide quantitative analysis documenting the impact of mitigation. DNV must disclose specific information related to the number of observations on the role of these mitigation measures and the reliability of the data set regarding their impact from the confidential study DNV prepared in 2002 that is the foundation for reductions from mitigation measures in the marine shipping QRA.

Similar concerns exist for mitigation measures at the marine terminal. In its limited assessment of mitigation measures for terminal operations, DNV claims that the closed loading system installed at Kitimat Terminal will eliminate the likelihood of spills from overfilling cargo tanks. Even in the event cargo tanks are overfilled, the closed loading system would redirect oil into nearby empty ship tanks "thereby eliminating the risk of an oil spill" (Brandsæter and Hoffman 2010 p. 131). DNV does not provide any historical evidence or data on the performance of closed loading systems to support this statement, which is concerning given that this single assumption eliminates any risk of a cargo tank overloading and more than doubles the unmitigated spill return period of 29 years to a mitigated return period of 62 years. Furthermore, given that the average loading/discharge operations at Kitimat Terminal is approximately 30 hours per year for each tanker (Brandsæter and Hoffman 2010 p. 5-74), there is no guarantee that a nearby tanker will be berthed at Kitimat Terminal in which to redirect oil into empty ship tanks.

6. *Inadequate evidence supporting the reduction of spill frequencies for pipeline operations*

The methodological approaches in the ENGP application estimating return periods for pipeline spills in *Volume 7B* and pipeline failure frequencies that affect public safety in the Bercha Group (2012b) study lack transparency. Both studies incorporate downward adjustments into calculations for pipeline spill frequencies without providing adequate evidence.

Enbridge estimates return periods for a pipeline spill in *Volume 7B* by adjusting spill frequency data from the NEB without disclosing how it made the downward adjustments and fails to provide evidence to justify the reductions. According to Enbridge (2010b Vol. 7B p. 3-1), NEB data from 1991 to 2009[7] includes pipelines up to 50 years old that use older technology and standards of building materials,

[7] Note that there is a discrepancy on page 3-1 of *Volume 7B*, since Enbridge references NEB data from 1991 to 200**0** as well as data from 1991 to 200**9**.

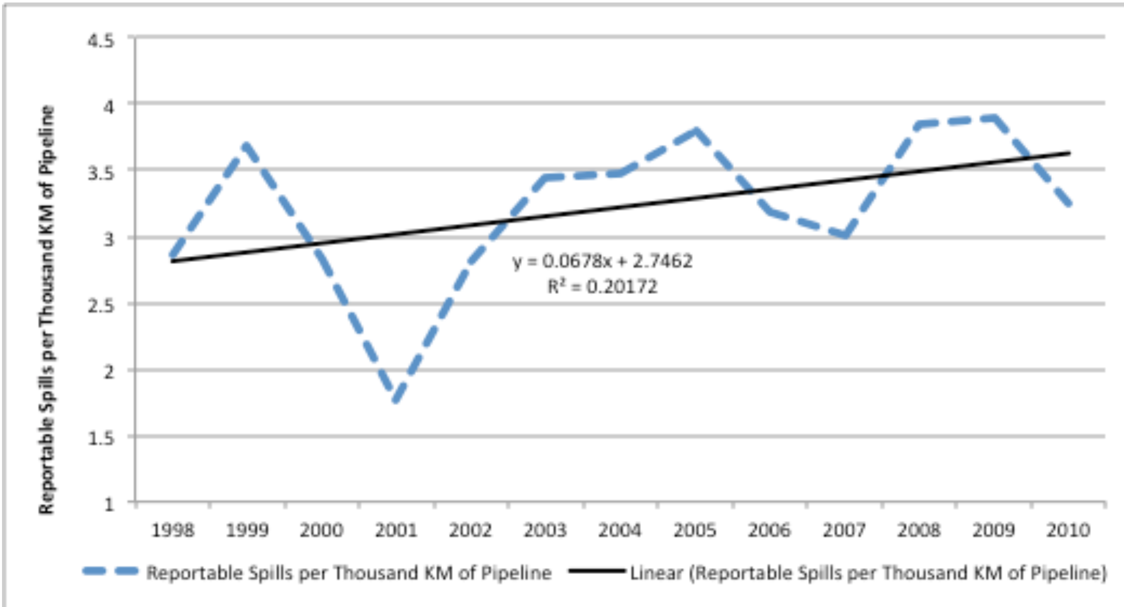
are not amenable to internal inspection, contain material that did not undergo inspection or quality control, and may have other characteristics associated with more failures compared to modern pipelines. Based on these assumptions and improved design and mitigation planning associated with modern pipelines, Enbridge claims that the aforementioned factors decrease the likelihood of pipeline failure and "were factored into failure frequency calculations for the pipelines" (Enbridge 2010b Vol. 7b p. 3-1). Enbridge does not provide proprietary data from the NEB, fails to present any spill rates or spill frequencies calculated from the NEB data, fails to explicitly explain how it adjusted incident frequencies, and presents no evidence to justify the downward adjustments. Furthermore, it is unclear whether the analysis includes the crude oil pipeline, condensate pipeline, or both pipelines combined.

Similarly, the Bercha Group (2012b) estimates failure frequencies for the ENGP pipeline based on historical pipeline rupture data from the NEB from 1991 to 2009 and makes several adjustments to the NEB data to incorporate various improvements in pipeline operations. The authors fail to adequately justify downward adjustments to several causes of pipeline ruptures including metal loss, cracking, and material failure that result in a decrease in the NEB failure rate of 71%. First, the Bercha Group reduces the failure frequency for metal loss (internal and external corrosion) by 80% based on a study by Muhlbauer (1996) entitled *Pipeline Risk Management Manual* and discussions with experts, although the authors provide no evidence to justify applying the reduction factor to the ENGP pipeline system other than suggesting that the ENGP pipeline is modern. Second, the Bercha Group reduces the failure frequency for cracking for the ENGP pipeline system by 90% compared to the NEB data claiming that "advanced coating technologies, low stress design, no tape coat, fatigue avoidance through design and operations, is expected to virtually eliminate cracking potential" (Bercha Group 2012b p. 3.5) without referencing a single study, expert opinion, data set, or other source of evidence. Third, the authors reduce the pipeline rupture frequency for material failure by 60% due to quality control during construction, inspection, testing, and other factors. Once again the report cites Muhlbauer (1996) but fails to justify the application of the reduction factor to the ENGP pipeline system and lacks evidence describing how the mitigation measures will achieve the stated reductions in spill frequency.

Historical spill performance for Enbridge's own pipeline system shows an increase in spill frequency. According to data submitted by Enbridge (2012a) to the Joint Review Panel for the ENGP providing the number of reportable spills per thousand km of liquids pipeline, the frequency of spills increases from 1998 to 2010 (see linear trendline in Figure 2). We recognize that this period is an insufficient amount of time to evaluate historical spill data but Enbridge does not publicly provide comprehensive spill data prior to 1998. We also recognize that spill data are not broken down by age of pipeline to allow for a direct comparison of newer to older pipelines. Nonetheless, Enbridge's own data show an increase in spill frequency that contradicts the downward adjustments that reduce spill frequencies in the

ENGP regulatory application. Furthermore, a comprehensive study of spill rates in the US also found that there was no decline in pipeline spill rates between 1972 and 2005 (Eschenbach et al. 2010)[8].

Figure 2: Historical Spill Performance of the Enbridge Liquids Pipeline System (1998 - 2010)



Source: Enbridge (2012a)

Recent spill data for the Keystone pipeline illustrates that new pipelines remain prone to spills. TransCanada operates the 3,460-km Keystone pipeline that delivers crude oil from Hardisty, AB to the US Midwest. As shown in Table 18, a total of 12 spills occurred in the US leg of the pipeline in the first year the Keystone began operation. Although the majority of the spills were less than 1 bbl, the 12 reported spills from the modern Keystone pipeline released a total of 505 to 555 bbl (80 to 88 m^3) in a single year of operation. Although the Keystone data is limited, it raises questions about the assumption of improved safety of new pipelines.

[8] Based on data representing US oil production in the Outer Continental Shelf region of the Gulf of Mexico from the Mineral Management Service between 1972 and 2005, Eschenbach et al. (2010) determine that although the number of pipeline spills < 1,000 bbl declined from 16 in 1972-1989 to 4 in 1990-2005, the decline does "… not demonstrate a statistically significant drop over time in the rate of pipeline spills" (p. 3-4).

Table 18: Recent Spill Record for the Keystone Pipeline (2010 - 2011)

Incident Date	Cause of Incident	Volume of Oil Spilled (bbl)
May 21, 2010	Valve body leak	< 1
June 23, 2010	Pump station leak	< 1
August 10, 2010	Unknown	< 1
August 19, 2010	Equipment failure	< 1
January 5, 2011	Faulty seal	< 1
January 30, 2011	Pump seal failure	< 1
February 3, 2011	Operator error	< 1
February 17, 2011	Equipment failure	< 1
March 8, 2011	Pump seal failure	< 1
March 16, 2011	Seal failure	3
May 7, 2011	Valve failure	450 – 500
May 29, 2011	Unknown	50
Total		**505 – 555**

Source: USCG NRC (2012); USDS (2011 Vol. 2 p. 3.13-13).

*Evaluation: There are six major deficiencies related to the transparency criterion and thus this criterion is **not met**.*

Replicability

Replicability: Documentation provides sufficient information to allow individuals other than those who did the original analysis to obtain similar results.

The ENGP regulatory application presents the methodologies used to estimate spill return periods for tanker, terminal, and pipeline spills in a fairly straightforward manner. However, insufficient information due to a lack of transparency prevents the replication of key components of the methodological approach and important results in the ENGP regulatory application. As suggested in the previous section, inadequate transparency prevents individuals other than the original analysts from replicating the following results and each component represents a major deficiency related to replicability:

1. ***LRFP frequency data for grounding, collision, foundering, and fire/explosion tanker incidents***
2. ***Scaling factors for ENGP routes due to a failure to provide comparative navigational routes used to determine scaling factors and methodology for determining scaling factors***
3. ***Conditional spill probabilities and spill size distributions estimated in the consequence assessment for tanker spills***
4. ***Mitigation measures that reduce spills from ENGP tanker traffic and marine terminal operations***
5. ***Incident frequencies and mitigation measures used to estimate return periods for pipeline spills.***

We acknowledge the difficulty in replicating certain results, particularly those based on random sampling from methods such as Monte Carlo simulation. However, proprietary data and the computer code for the Monte Carlo simulation model should be included in an appendix or separate data report in order to allow an independent party to conduct similar tests and compare results with those included in the ENGP regulatory application.

*Evaluation: There are five major deficiencies related to the replicability criterion and thus this criterion is only **not met**.*

Clarity

Criterion: Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision-making.

Decision makers must use the criterion for likelihood of significant adverse environmental effects for project assessment under *CEAA*. Methodologies that calculate and present spill likelihood in the ENGP regulatory application do not provide a clear assessment of the likelihood of spill occurrence. There are five major deficiencies related to clarity in the methodological approach for estimating return periods for ENGP tanker, terminal, and pipeline spills:

1. Failure to effectively communicate the probability of a spill over the life of the project

Enbridge expresses the likelihood of a spill as a return period rather than the probability of a spill over the life of the project, which presents a major deficiency in the communication of spill estimates to decision-makers. A return period is the number of years between spill events and is the inverse of the probability. Thus, if the unmitigated return period for any size oil or condensate spill is 78 years, there is a 1 in 78 chance, or approximately 1% probability, that a spill will occur each year. Return periods incorrectly imply that an oil spill event will occur only once throughout the recurrent interval, such as 78 years, when in fact the event can occur numerous times or not at all. Furthermore, return periods do not communicate the probability of a spill during the operational life of the ENGP, which ranges from 30 to 50 years[9]. Without estimates of the probability of a spill over the operating life of the project, decision makers are unable to determine whether the project meets the *CEAA* criterion of likelihood of adverse environmental effects. Indeed, stating that there is a 22.2% chance of a tanker spill exceeding 5,000 m^3 over the operating life of the ENGP, instead of reporting that

[9] The Wright Mansell report entitled *Public Interest Benefits of the Enbridge Northern Gateway Pipeline Project* appended to Enbridge (2010b Vol. 2) assumes a 30-year operating period whereas Enbridge assumes a 50-year operating period for pipeline operations in *Volume 7B: Risk Assessment and Management of Spills – Pipelines*.

there will be one spill every 200 years, more effectively communicates the likelihood of a spill to decision-makers[10].

2. Failure to combine estimates for tanker, terminal, and pipeline spills to present a single spill estimate for the entire project

A second major deficiency is Enbridge's failure to estimate spills for the entire ENGP. The risk assessment for marine transportation in *Volume 8C*, the risk assessment for pipelines in *Volume 7B*, the marine shipping QRA prepared by DNV, and the Bercha Group (2012a; 2012b; 2012c) and WorleyParsons studies all present separate spill estimates. Enbridge does not combine separate estimates for tanker, terminal, and pipeline spills, as well as their component parts including pumps, storage tanks, and pump stations to demonstrate the collective likelihood of a spill from all potential spill sources. By presenting separate spill return periods for individual components of the project instead of the entire project, Enbridge underestimates spill likelihood and fails to provide decision makers with the overall spill risk information necessary for applying the *CEAA* decision criterion.

To address the lack of clarity in the ENGP application, we restate spill return periods estimated by Enbridge and their consultants by converting return periods to annual spill probabilities and estimate spill probabilities over the life of the project rather than on an annual basis[11]. Based on Enbridge's analysis, the restated probability of any size oil or condensate tanker spill over the life of the ENGP ranges from 11.3% to 47.5% (Table 19). The probability of a spill increases significantly to 99.9% when spill probability is evaluated for the entire ENGP inclusive of tanker, terminal and pipeline spills[12]. Our revised estimates in Table 19 likely underestimate spill probabilities because they are based on estimates in the ENGP regulatory application that understate risk due to data limitations and undocumented mitigation adjustments[13]. Therefore actual spill probabilities are likely higher.

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[10] To estimate the chance of a 5,000 m^3 oil spill over a 50-year operating period, we calculate the inverse of the return period for a 5,000 m^3 spill (200 years) to estimate the annual probability of a spill (0.005 or 0.5%) and use the formula in footnote 11 to obtain a 22.2% probability over 50 years.

[11] We use the following formula to convert annual probabilities to probabilities over a 30- and 50-year period: $1 - ((1 - P)^n)$, where P is the annual probability and n is the number of years.

[12] Return period calculated based on the following spill probabilities: (1) any size tanker spill; (2) any size terminal spill, and; (3) pipeline leaks. We note that Enbridge's consultants estimated an overall probability of 70.9% over 50 years during the hearings (Enbridge 2012b Vol. 78 p. 53). However, this lower probability is based on any size oil/condensate tanker spill (18.2%), any size oil/condensate terminal spill (56.2%), and an oil pipeline rupture (18.8%). This approach is not representative of overall spill probability for the ENGP because it relies on the likelihood of a pipeline rupture, which is less likely to occur than a leak, and omits condensate pipeline spills.

[13] Data limitations in the ENGP application include estimating spill likelihood for tankers with LRFP data that potentially underreport actual tanker spills, omitting the majority of the distance travelled by tankers to export markets, potential double-counting of mitigation measures, and failing to consider characteristics of the project that could increase risk such as the corrosiveness of diluted bitumen and maneuverability

Table 19: Spill Probabilities Over the Life of the ENGP Based on Regulatory Application

	Probability over 30 Years (%)	Probability over 50 Years (%)
Tanker Spill		
Any size oil/condensate	11.3 - 32.1	18.2 - 47.5
Any size oil	8.2 - 24.0	13.3 - 36.7
Oil > 5,000 m^3	5.3 - 14.0	8.7 - 22.2
Oil > 20,000 m^3	1.1 - 1.7	1.8 - 2.8
Oil > 40,000 m^3	0.2	0.3 - 0.4
Terminal Spill		
Any size oil/condensate	38.6 - 65.1	55.6 - 82.7
Any size oil	28.5 - 59.2	42.8 - 77.5
Pipeline Spill^		
Oil/Condensate leak	99.9	99.9
Oil leak	99.9	99.9
Tanker, Terminal, or Pipeline Spill*		
Oil/Condensate	99.9	99.9
Oil	99.9	99.9

Source: Calculated based on Brandsæter and Hoffman (2010) and WorleyParsons (2012).
Note: Range represents mitigated and unmitigated spill probabilities with the exception of pipeline spills
* Overall spill probability for ENGP based on any size tanker spill, any size terminal spill, and pipeline leaks.
^ Average size oil or condensate pipeline leak is 94 m^3 (WorleyParsons 2012).

3. *Failure to determine the likelihood of all spill size categories that can have a significant adverse environmental impact*

Another deficiency is the failure to estimate spill likelihood for all spill size categories that can have a significant adverse environmental impact, particularly smaller spills. In its marine shipping QRA, DNV presents return periods for any size oil/condensate spill as well as return periods for several categories of oil spill volumes including spills greater than 5,000 m^3, 10,000 m^3, 20,000 m^3, and 40,000 m^3. However, DNV fails to examine the likelihood of spills for specific spill volumes less than 5,000 m^3 despite the potential significant effects of smaller spill volumes.

The US environmental impact assessment of potential oil spills in Cook Inlet, Alaska (US DOI 2003a), an area with similar characteristics as the BC study area, predicts that an oil spill of 238 m^3 (1,500 bbl) could have significant adverse environmental impacts. The US DOI (2003a) environmental impact statement assesses economic, environmental, and sociocultural impacts associated with the exploration, development, and production of the Cook Inlet Outer Continental Shelf in Alaska. One component of the study involves an assessment of the effects of a large oil spill, which the US DOI defines as a spill greater than or equal to 1,000 bbl (159 m^3). The authors use the OSRA model with spill rates from Anderson and LaBelle (2000) to determine spill occurrence and an oil spill trajectory model that reflects physical conditions of the environmental setting to determine the chance that the spill might contact environmental resources. The authors then estimate impacts to economic, environmental, and sociocultural resources affected by the

differences among tankers. In terms of undocumented mitigation adjustments, DNV does not provide evidence for its downward adjustments that significantly reduce the likelihood of tanker and terminal spills.

hypothetical spill based on the modeling results, characteristics of the affected environment, documented impacts from previous spills in the Alaska region (i.e. Glacier Bay and Exxon Valdez) and peer-reviewed studies. The Cook Inlet environmental impact statement estimates the following potentially **significant**[14] impacts from a 1,500 bbl (238 m^3) oil platform spill or a 4,600 bbl (731 m^3) pipeline spill:

- Beach and intertidal fish habitat impacts could last more than a decade from residual oil
- Mortality of endangered and threatened species such as sea otters and Steller sea lions could occur
- Commercial fisheries could close for an entire season due to tainting concerns
- Oil remaining in shoreline sediments for up to 10 years could impact clam and shellfish sport fisheries
- Recreation and tourism areas could close partially or completely
- Oil spill cleanup activities could disturb archaeological resources
- Negative effects could occur to intrinsic values of National and State parks.

In addition to significant effects, the environmental impact statement also identifies the following spill effects to other marine-related resources that could occur from a 238 to 731 m^3 oil spill in Cook Inlet:

- The spill could impact an area between 618 and 1,100 km^2
- Between 17 to 38 km of shoreline could be contaminated for up to a decade
- Water quality in the vicinity of the spill would be at chronic toxicity levels for up to 30 days
- Local intertidal and lower trophic-level organisms could be depressed measurably for about one year
- Mortality of adult fish, fish fry, and eggs could occur, although there would be no measurable loss to overall fish populations
- Mortality of hundreds to tens of thousands of birds could occur and recovery could take from a few years to a few generations
- Mortality of small numbers of resident marine mammals and recovery could take from one to five years, although no measurable decline in regional populations are expected

[14] The US DOI uses a definition for significance consistent with the Council on Environmental Quality National Environmental Policy Act (NEPA) regulations, which defines significance in terms of context and intensity (US DOI 2003a p. IV-1):

> "Context" considers the setting of the Proposed Action, what the affected resource might be, and whether the effect on this resource would be local or more regional in extent. "Intensity" considers the severity of the impact, taking into account such factors as whether the impact is beneficial or adverse; the uniqueness of the resource (for example, threatened or endangered species); the cumulative aspects of the impact; and whether Federal, State, or local laws may be violated…Our (*US DOI*) EIS (*environmental impact statement*) impact analyses address the significance of the impacts on the resources considering such factors as the nature of the impact (for example, habitat disturbance or mortality), the spatial extent (local and regional), temporal and recovery times (years, generations), and the effects of mitigation (for example, implementation of the oil-spill-response plan).

- Mortality of a small number of terrestrial mammals and recovery could take one to three years
- Disproportionately high adverse effects would occur to Native populations resulting from potential contamination of subsistence harvest areas, tainting concerns and disruption of subsistence practices.

In summary, DNV fails to determine the likelihood of a spill for all spill sizes that can have a significant adverse environmental impact and fails to provide supporting evidence for using 5,000 m^3 as the implied cut off for significant adverse effects.

4. Lack of clear communication of spill estimates generated in detailed technical data reports in the main ENGP application

A fourth deficiency is Enbridge's failure to clearly state spill estimates generated in the detailed technical reports in the main application report. For example, Enbridge summarizes the 139-page Technical Data Report *Marine Shipping Quantitative Risk Analysis* prepared by DNV in just 23 pages in the *TERMPOL Study,* in just two pages in *Volume 7C,* and four pages in *Volume 8C* of the ENGP regulatory application. The executive summary of the Enbridge application summarizes the risk of tanker spills in just one paragraph that states (Enbridge 2010b Vol. 1, p.11-35):

> For risk related to vessel transits within the Territorial Sea of Canada with inclusion of navigation safety mitigation (primarily the use of tethered and close escort tugs), the calculated return period of a spill of any size from a tanker carrying oil is 350 years. For condensate, the return period is 890 years. The return period for large scale releases increases (risk level decreases) substantially to a level of 550 years for a spill exceeding 5,000 m^3, 2,800 years for a spill exceeding 20,000 m^3 and more than 15,000 years for a spill exceeding 40,000 m^3.

A significant amount of important information required to inform decision-makers is missing from both the *TERMPOL study* and *Volumes 1, 7C* and *8C* of the ENGP application, including information on the methodological approach, data gaps and limitations, assumptions used throughout the analysis, any uncertainties associated with results, and the sensitivity analysis.

Enbridge presents spill return periods for pipeline operations in three pages in *Volume 7B* and there is no reference to a technical data report or appendix containing a more comprehensive analysis of pipeline spills. Thus not only is the information on pipeline spills inadequate in *Volume 7B*, but no data report exists to clarify the methodology, data, assumptions, and limitations that clearly and comprehensively explain how pipeline spill return periods were evaluated[15]. The

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[15] Note that although the WorleyParsons (2012) report examines a full-bore pipeline rupture and the Bercha Group (2012b; 2012c) reports examine pipeline spills at pump stations and a pipeline spill in densely

disconnect between data reports and the main ENGP regulatory application, as well as the complete absence of a data report for pipeline spills, reduce accessibility to critical information, present barriers to the effective communication of spill likelihood to stakeholders, and could negatively impact the decision-making process.

5. Failure to clearly address the effective implementation of mitigation measures that reduce risk

Another consideration related to clarity concerns the presentation of mitigation measures that purportedly reduce risk without discussing the effective implementation of risk management measures. In the marine shipping QRA, DNV identifies mitigation measures that it claims will reduce the likelihood of a spill. Enbridge's consultants state "Should any of these requirements not be met the risk reduction effect would decrease accordingly." (Brandsæter and Hoffman 2010 p. 8-120). Ensuring effective implementation is the responsibility of the company and the NEB, which is responsible for regulating companies' activities. The enforcement and monitoring record of the NEB raises serious doubts about the effectiveness of implementing risk management. According to an audit performed by the Commissioner of the Environment and Sustainable Development (2011 p. 10), nearly two-thirds (64%) of the compliance verification files reviewed by the NEB identified deficiencies and only 7% of those files provided evidence the NEB followed up with companies to determine if deficiencies were corrected. Further, 100% of the emergency response plans reviewed had deficiencies and there was a follow-up to address the deficiencies in only one case (CESD 2011 p. 11). Thus, if Enbridge fails to implement mitigation measures and the NEB fails to take corrective action, spill likelihood could significantly exceed Enbridge' s estimates that assume effective implementation of all risk-reducing mitigation measures.

Furthermore, inadequate monitoring and enforcement have implications for emergency response in the event that a spill from the ENGP occurs. If the NEB fails to enforce emergency response initiatives outlined by Enbridge in the ENGP application to respond to a spill, a similar situation may result as the 20,000-bbl diluted bitumen spill that shutdown sections of the Kalamazoo River near Marshall, Michigan in July 2010 (NTSB 2012). Factual reports from the NTSB investigation into the spill characterize Enbridge's response as incompetent in the detection and shutdown of the spill and suggest that Enbridge demonstrated inadequate preparation to contain the spill. Indeed, Enbridge control room operators failed to detect or attempt to shutdown the ruptured pipeline for 17 hours even though monitoring systems repeatedly sounded alarms and displayed low-pressure readings (NTSB 2012). After the spill was detected, Enbridge experienced considerable difficulties locating contractors and other resources in the region to contain the spill and waited for the US Environmental Protection Agency to eventually provide the contact information for contractors (NTSB 2012).

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populated areas, both of these reports are standalone studies that are independent from *Volume 7B* and were submitted two years after the initial application.

In its regulatory application for the ENGP, Enbridge outlines a general spill response plan and claims that equipment will be pre-staged to improve response time (Enbridge 2010b Vol. 8C p. 5-1). However, the weak monitoring record of the NEB (CESD 2011) and Enbridge's recent mismanagement of the Line B spill in Michigan suggest that any mitigation measures identified in the ENGP application to reduce spill likelihood and minimize spill damage must include a risk assessment of the likelihood of implementation failure and must be accompanied by a detailed implementation plan that clearly outlines a comprehensive monitoring and verification program[16].

*Evaluation: There are five major deficiencies related to the clarity criterion and thus this criterion is **not met**.*

Reasonableness

Reasonableness: The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment.

The methodological approach estimating spill return periods for the ENGP contains five major deficiencies related to the reasonableness criterion. Major deficiencies include:

1. Inappropriate definition of the study area to estimate spill return periods for tanker operations

DNV calculates return periods for tanker spills based on an inappropriate definition of the study area. Although a sensitivity analysis extends the transit area to 200 nm off the BC coast, DNV does not calculate the likelihood of a spill for the entire tanker voyage to any key export markets in Asia or the US, nor does it examine the potential effects of a spill outside of the narrowly defined BC study region.

DNV limits its analysis of tanker incident frequencies to three shipping routes within Canada's Territorial Sea that represent an average of 233 nm. Yet, one-way sailing distances from Kitimat, BC to the three key Northeast Asia markets of Shanghai, China, Yokohama, Japan, and Ulsan, South Korea range from 4,041 to 4,865 nm (Enbridge 2010b Vol. 2 App. A p. 13) and the approximate one-way distance from Kitimat to San Francisco and Los Angeles, California are respectively 1,051 nm and 1,391 nm (Sea Distances - Voyage Calculator undated). Thus, DNV ignores an average of nearly 4,200 nm to key markets in Asia and 1,000 nm to markets in the US per tanker route, which represents a significant exclusion of the distances navigated by tankers (Table 20). Assuming 149 oil tankers sail at least one leg of their voyage to Asia or the US, one-way distance shortfalls per tanker

[16] We acknowledge that the Enbridge spill in Michigan occurred in a different jurisdiction than that regulated by the NEB. However, we reference the mismanagement of the spill to demonstrate that poor implementation of a spill response plan can have serious consequences.

amount to the omission of over 624,000 nm to Asia markets and over 147,000 nm to markets in the US per year.

Table 20: Differences in Nautical Miles used to Estimate Tanker Spills and Actual Nautical Miles to Key Export Markets

Key Export Market	One-way Distance to Market (in nm)	Average One-way Distance in Study Area (in nm)	One-Way Distance Shortfall Per Tanker (in nm)	Total Distance Shortfall Per Year (in nm)
Asia Markets				
Shanghai, China*	4,865	233	4,631	690,044
Yokohama, Japan*	4,041		3,808	567,342
Ulsan, South Korea*	4,363		4,129	615,246
Average	**4,423**		**4,189**	**624,211**
US Markets				
San Francisco**	1,051	233	818	121,832
Los Angeles**	1,391		1,158	172,492
Average	**1,221**		**988**	**147,162**

Source: Brandsæter and Hoffman (2010 p. 3-1); Enbridge (2010b Vol. 2 App. A p. 13); http://sea-distances.com/
* We calculate nautical miles as half of the round-trip distance to all three regions in Enbridge (2010b Vol. 2 App A. p. 13).
** We calculate nautical miles from Kitimat to San Francisco and Los Angeles using the calculator from http://sea-distances.com/

Failure to consider spills outside the study region is contrary to *CEAA,* which requires an assessment of environmental effects that would occur "outside Canada" (*CEAA* Sec. 5). Thus, DNV's methodological approach that ignores the majority of the distance sailed by tankers to key export markets significantly underestimates spill likelihood and prohibits decision-makers from determining significant adverse environmental effects of the ENGP outside Canada required under *CEAA*.

2. Failure to adjust tanker incident frequency data to correct for underreporting

Literature in peer-reviewed sources suggests that vessel accident data reported in the LRFP database, which DNV uses to determine tanker incident frequencies in the marine shipping QRA, have serious deficiencies. Hassel et al. (2011) examine the LRFP database for underreporting of foundering, fire/explosion, collision, wrecked/stranded, contact with a pier, and hull/machinery accidents for merchant vessels exceeding 100 gross tonnes registered in particular states (flag states) including Canada, Denmark, Netherlands, Norway, Sweden, United Kingdom, and the US from January 2005 to December 2009. Using various statistical methods, the researchers estimate that reporting performance by LRFP ranges between 4% and 62% for select flag states compared to actual accident occurrences, suggesting that as few as one in 25 accidents were reported in the LRFP database for a particular flag state over a five-year period[17]. In the best-case scenario for vessel

[17] Hassel et al. (2011) suggest that results should be interpreted with caution due to assumptions and estimation methods used by the authors. However, according to Hassel et al. (2011), their findings are consistent with those made in the study by Psarros et al. (2010).

accidents in Canada, the LRFP database reports 69% of all accidents and thus omits nearly one-third (31%) of all accidents occurring for vessels with a Canadian flag (Hassel et al. 2011). A separate study conducted by Psarros et al. (2010) observes similar underreporting in the LRFP database for accidents from vessels registered in Norway. Based on an analysis of accident data for merchant vessels exceeding 100 gross registered tonnage from February 1997 to February 2007, the researchers estimate that at best only one in three (30%) occurred accidents are reported in the LRFP database[18]. Thus, the LRFP database has no record for 70% of accidents from vessels registered in Norway over a 10 year period. Furthermore, Psarros et al. (2010) observe that the effect of the vessel's size on reporting performance is insignificant and that the seriousness of an accident does not have a significant effect on the likelihood of the accident being reported. The relationship between incident frequency underreporting in the LRFP database and spill frequency is unknown due to DNV's failure to include proprietary data from LRFP in its study.

To address underreporting, Hassel et al. (2011) suggest that statistical accident data should be accompanied by adjustments such as correction factors, safety margins, or expert judgment. DNV did not adjust data derived from the LRFP database to incorporate any uncertainties associated with LRFP data in their methodological approach. Even if underreporting relates to minor incidents and has only a minimal effect on incident frequencies, DNV should, at the very least, disclose the known issue of incomplete LRFP data in a transparent manner and describe why analysts did not adjust the data accordingly. DNV's failure to acknowledge deficiencies in LRFP data and to make adjustments to reflect potential underreporting is particularly surprising given that the authors of the article documenting underreporting were employees of DNV when the article was published in 2010.

3. Potential double-counting of mitigation measures for LRFP tanker incident data

DNV decreases the likelihood of tanker spills by adjusting LRFP data with mitigation measures based on the use of escort and tethered tugs at Kitimat Terminal. DNV claims that the use of escort and tethered tugs will reduce the frequency of powered and drift groundings 80% to 90% and will reduce collision incidents 5% compared to tanker incidents without these mitigation measures (Brandsæter and Hoffman 2010 p. 8-120). As a result of these mitigation measures, spill likelihood decreases three-fold from an unmitigated return period of 78 years for any size oil or condensate tanker spill to a mitigated return period of 250 years.

LRFP tanker incident data may already represent locations that use escort tugs for tanker traffic and thus DNV's downward adjustments to the LRFP data may double-count mitigation measures that reduce spill likelihood. According to DNV,

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[18] Psarros et al. (2010) point out that, although their findings coincide with previous studies (Norway 2008 and Thomas and Skjong 2009 as cited in Psarros et al. 2010), the results should be treated carefully.

LRFP data represent international tanker incident frequencies between 1990 and 2006 (Brandsæter and Hoffman 2010 p. 5-49). A report entitled *Study of Tug Escorts in Puget Sound* prepared by The Glosten Associates for the Washington State Department of Ecology in 2004 discusses the current and historical use of escort tugs at several international ports in a time period that overlaps with the 1990-2006 data used by DNV in its estimate of tanker incidents for the ENGP. In 2004 when the study was released, escort tugs were required under state or federal law in at least four locations in the United States and a further nine locations voluntary used escort tugs for inbound and outbound tankers (Glosten 2004 p. 8-9) (Table 21). DNV provides no evidence in the QRA that it adjusted the LRFP dataset for ports where escort tugs are already in use. Therefore if these adjustments were not made, the downward adjustments to LRFP data double count mitigation impacts of tugs and underestimate the actual spill risk for ENGP tankers.

Table 21: Escort Tug Usage at International Tanker Ports

Location	Escort Tug Usage
Puget Sound, Washington	Mandatory
Prince William Sound, Alaska	Mandatory
San Francisco Bay, California	Mandatory
Los Angeles/Long Beach, California	Mandatory
Whiffenhead, Newfoundland	Voluntary
Mongstad, Norway	Voluntary
Rafsnes, Norway	Voluntary
Brofjorden, Sweden	Voluntary
Gothenburg, Sweden	Voluntary
Porvoo, Finland	Voluntary
Sullom Voe, Scotland	Voluntary
Milford Haven, England	Voluntary
Liverpool, England	Voluntary

Source: Adapted from Glosten (2004 p. 8-9)

4. Inadequate consideration of the corrosiveness of diluted bitumen associated with internal corrosion that may increase spill frequency

The methodological approach estimating spill frequencies provides an inadequate treatment of the corrosiveness of dilbit that contains higher sulphur concentrations (EC OPD 2012). Enbridge does not incorporate the potential for increased corrosion associated with transporting dilbit into return periods for pipeline spills in *Volume 7B* nor does DNV include it in their methodology for determining tanker and terminal spill return periods. The Bercha Group (2012b) study evaluating pipeline failure frequencies that affect public safety recognizes internal and external corrosion as potential causes for pipeline failure but significantly reduces risk from corrosion by 80% without adequate justification. Further, WorleyParsons (2012) states that the threat of internal and external corrosion is negligible and thus excludes corrosion in their estimates of pipeline spills.

Evidence suggests that sulphur concentrations in dilbit may increase the corrosiveness of metals used for ENGP tanker, terminal, and pipeline operations. Higher sulphur concentrations can present a corrosive threat to the integrity of metals (Lyons and Plisga 2005) including metals used for pipelines, storage tanks, and cargo holds. According to Environment Canada's Oil Properties Database, the sulphur content of West Texas Intermediate oil ranges between 0.34% to 0.57% whereas the sulphur content for Athabasca Bitumen ranges from 4.41% to 5.44% (EC OPD 2012), or between nine and 12 times higher than the benchmark of West Texas Intermediate. Hence, the higher sulphur content in dilbit presents a potential increased risk of failure from internal corrosion for metals used in the construction of pipelines, tankers, and storage tanks for the ENGP.

Higher internal corrosion rates associated with the transportation of dilbit are evident in the comparison of corrosion incidents between Alberta and US pipeline systems. Between 1990 and 2005, internal corrosion accounted for nearly a quarter (24.8%) of crude oil pipeline incidents in Alberta (AEUB 2007). In comparison, internal corrosion incidents for crude oil pipelines in the US represented less than one-sixth (13.7%) of all pipeline incidents between 1986 and 2009 (US PHMSA 2012)[19]. Although these findings do not prove that increased corrosiveness associated with transporting dilbit caused a higher rate of failure in the Alberta pipeline system compared to the US system, the results illustrate that more information is needed on the corrosiveness of dilbit to metals used for ENGP operations.

In summary, the risk analysis should incorporate any potential increases in corrosiveness from transporting and handling dilbit in an appropriate manner to ensure that the potential for higher failure rates are quantified in probabilistic terms. Increased corrosion could negate any risk reducing effects from mitigation measures that purportedly decrease the likelihood of tanker, terminal, and pipeline spills.

5. Failure to consider different vessel characteristics in tanker incident frequencies

There are two principle concerns related to vessel characteristics in the estimation of tanker incident frequencies. First, DNV's methodology in its marine shipping QRA fails to differentiate between VLCC, Suezmax, and Aframax tankers for tanker and terminal spills, even though Enbridge recognizes distinct maneuverability differences among tanker classes. According to DNV, "The incident frequencies derived from the LRFP data are considered to be valid for all three tanker classes forecast to call at Kitimat Terminal. Tanker incident frequencies are influenced more by the specific shipping route, than the type of tanker" (Brandsæter and

[19] We calculate the proportion of internal corrosion incidents based on separate incident data from the PHMSA for 1986-2001 and 2002-2009. Between 1986 and 2001, the PHMSA reported 1,263 total incidents, 168 (13.3%) of which were due to internal corrosion. Between 2002 and 2009, PHMSA reported 182 internal corrosion incidents out of 1,291 total incidents or 14.1%. Both data sets represent internal corrosion incidents for onshore crude oil pipelines.

Hoffman 2010 p. 5-49). However, a report prepared for Enbridge by FORCE Technology entitled *Maneuvering Study of Escorted Tankers to and from Kitimat: Real-time Simulations of Escorted Tankers for a Terminal at Kitimat* clearly determines distinct differences among VLCC, Suezmax, and Aframax tankers for several maneuverability characteristics including steering ability, turning ability, and stopping ability. In terms of steering ability, FORCE determines that VLCCs require over one and a half times the distance to conduct a zigzag test[20] than Aframax tankers with both vessels in laden condition (see Figure 4-1 in FORCE 2010). Similarly, for the turning ability test[21] for laden tankers, results show a considerably larger area required to turn VLCCs than both Suezmax and Aframax tankers when at full sea speed and at 10 knots (See Figures 4-2 and 4-2 in FORCE 2010). Finally, in terms of stopping ability, loaded VLCCs require nearly one and a half times the stop distance compared to Aframax tankers and nearly twice the distance than Suezmax tankers at 10 knots when the engines are running astern at full power (Figure 4-5 in FORCE 2010).

Based on the detailed findings in the report submitted by FORCE, there are indeed very different maneuverability characteristics among VLCCs, Suezmax, and Aframax tankers navigating shipping routes. Thus, DNV's assumption of uniformity among the three tanker classes fails to incorporate any of the distinct handling capabilities of each tanker that could affect incident rates. Depending on the nature of the LRFP data, the uniformity assumption potentially results in an underestimate of particular incident occurrences for VLCCs compared to Suezmax and Aframax tankers if VLCCs have a higher incident frequency and the LRFP incident data largely consist of incident frequencies for Suezmax and Aframax tankers. DNV's failure to include proprietary LRFP data prevents any verification of incident occurrence rates for the various tanker classes, however Eliopoulou and Papanikolaou (2007) found that tanker incidents with serious consequences or total losses and spillage rates between 1990 and 2003 were highest for VLCCs compared to Aframax and Suezmax tankers.

A second consideration is the relative incident frequencies among different age classes of tankers. A recent study from Eliopoulou et al. (2011) examines the relationship between tanker age and accidents in tanker casualty data from the LRFP database after the Oil Pollution Act of 1990. The authors determine that incident rates for non-accidental structural failure, or what DNV refers to as foundering, vary significantly depending on the age of the double-hull tanker. Indeed, non-accidental structural failure tanker incidents for double-hull tankers

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[20] According to FORCE, tankers perform the zigzag test by "…commanding the rudder 10 deg. to port. When the ship has changed its course 10 deg. from its initial course, the rudder is commanded 10 deg. to starboard. When the ship has changed its course 10 deg. to starboard from its original course, the rudder is again commanded 10 deg. to port." (FORCE 2010 p. 19). The test completes after two zigzags.

[21] Tankers perform the turning ability test by "…commanding the rudder 35 deg. to starboard while the engine is running at the maximum load. As the ship starts to turn, a great part of the ship's longitudinal speed is transferred into a transverse (drift) speed that due to the great resistance reduces the longitudinal speed significantly." (FORCE 2010 p. 20).

ranging between 16 and 20 years[22] are over 2.5 times higher compared to tankers aged 11 to 15 years and over 4 times higher compared to tankers aged 6 to 10 years. In 2009, the authors estimate that the average age of double hull tankers in the worldwide operational fleet was between 4 and 8 years. Papanikolaou et al. (2009) estimate that, due to the young age of the worldwide tanker fleet, non-accidental structural failures could become significant after 2020, which is the date that ENGP plans to be in full operation. Thus, historical incident frequency data from the LRFP database may underestimate future incident rates for non-accidental structural failures for ENGP tankers since the methodological approach in the QRA does not consider the likely increase in double-hull tanker age during the operating period of the ENGP.

In summary, DNV's methodology should differentiate tanker incidents and spill rates among the different tanker classes and different tanker ages. Failure to consider different vessel characteristics results in a potential underestimate of future tanker accidents.

*Evaluation: There are five major deficiencies related to the reasonableness criterion and thus this criterion is **not met**.*

Reliability

Reliability: Appropriate analytical methods explicitly describe and evaluate sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk.

The methodological approach estimating spill return periods in the ENGP regulatory application contains two major deficiencies related to the reliability criterion:

1. Lack of confidence intervals that communicate uncertainty and variability in spill estimates for tanker, terminal, and pipeline operations

The methodologies estimating tanker, terminal, and pipeline spills for the ENGP fail to provide confidence intervals that characterize and communicate uncertainty and variability. There are no confidence intervals for any of the spill estimates or failure frequencies in *Volume 7B*, *Volume 8C*, the *TERMPOL Study*, the marine shipping QRA prepared by DNV, the Bercha Group (2012a; 2012b; 2012c) studies, or the WorleyParsons (2012) report. Since confidence intervals provide a measure of the precision of a calculated value and describe the uncertainty surrounding an estimate, the absence of confidence understates the degree of risk. Failure to present confidence intervals implies that there is little or no uncertainty in spill estimates and provides a false sense of confidence in the results. Thus spill estimates for the ENGP fail to provide a measure of precision, fail to communicate uncertainty in spill-related data, and potentially mislead decision-makers to presume that there is certainty in the estimates even though this is not the case.

[22] Enbridge has stated that it will not use tankers over 20 years of age in an effort to prevent hydrocarbon spills (Enbridge 2010c).

2. *Failure to complete a sensitivity analysis that effectively evaluates uncertainty associated with spill estimates*

The various technical reports addressing spill likelihood submitted for the ENGP exclude comprehensive sensitivity analyses that measure the uncertainty of spill estimates in a meaningful way. The analysis of pipeline spills in *Volume 7B* of the ENGP application, the analyses prepared by the Bercha Group (2012a; 2012b; 2012c), and WorleyParsons (2012) do not contain sensitivity analyses.

DNV completed a sensitivity analysis in the marine shipping QRA although it contains several deficiencies. First, the limited sensitivity analysis for tanker traffic in the marine shipping QRA examines only four parameters: increased scaling factor for grounding, increased traffic density, increased/decreased number of tankers calling Kitimat Terminal, and extending segments 5 and 8 by 200 nm. DNV fails to examine sufficient increases in parameters, particularly increases in tanker traffic associated with its expansion scenario that increases oil pipeline throughput to 850 kbpd and condensate pipeline throughput to 275 kbpd (Enbridge 2010b Information Request No. 3). This increased volume would result in an increase in tanker traffic of 50%, much higher than the 14% increase in tanker traffic used by DNV in its sensitivity analysis. The higher tanker traffic would in turn significantly increase spill likelihood. Second, DNV does not examine changes in critical parameters such as conditional probabilities and incident frequencies to determine their effect on spill likelihood. Since incident frequencies and conditional probabilities are multiplied together, any uncertainty in these estimates propagate through to the final estimate of spill likelihood and could result in significant changes to spill return periods. The uncertainty of these critical parameters must be tested with a comprehensive sensitivity analysis. Third, there is no sensitivity analysis for mitigated tanker operations, as well as unmitigated and mitigated spills at the marine terminal. Fourth, the sensitivity analysis for tanker spills only tests one parameter change at a time and does not assess the impact of simultaneously changing multiple parameters. Fifth, other important regulatory documents such as *TERMPOL STUDY NO. 3.15: General Risk Analysis and Intended Methods of Reducing Risk* and *Volume 8C: Risk Assessment and Management of Spills – Marine Transportation* do not refer to the limited sensitivity analysis completed in the marine shipping QRA. Thus, the sensitivity analysis for ENGP spill estimates evaluates only four parameters for the entire project, ineffectively measures the magnitude of uncertainties, and results fail to appear in main studies submitted by Enbridge for the ENGP regulatory application.

*Evaluation: There are two major deficiencies related to the reliability criterion and thus this criterion is **not met**.*

Validity

Validity: Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis.

The absence of expert review for the majority of the ENGP regulatory application related to spill return periods represents one major deficiency. Furthermore, the lack of third party, independent expert reviewers for components of the risk analyses to undergo expert review represents another major deficiency related to the validity criterion.

1. *Inadequate review and validation of spill estimates for tanker, terminal, and pipeline operations*

There is no evidence to suggest that the majority of findings in *Volume 7B*, *Volume 8C*, DNV's marine shipping QRA, *TERMPOL Study No. 3.15,* the Bercha Group (2012a; 2012b; 2012c) studies or the WorleyParsons study were reviewed or validated by experts. *Volume 7B* and *Volume 8C* of the ENGP regulatory application and the Bercha Group (2012c) study contain no reference to any expert peer review or validation of estimates for tanker, terminal, and pipeline spills. DNV's methodological approach in the marine shipping QRA (and partly summarized in the *TERMPOL Study*) underwent expert review to identify and evaluate hazards that influence tanker risk, as well as validate local scaling factors that adjust tanker operations to the BC study area. However, these two components represent only a portion of the larger methodology estimating return periods for tanker spills and DNV did not undertake expert review and validation of important findings related to incident frequencies, conditional probabilities, and mitigation measures, as well as return periods for tanker and terminal spills. The Bercha Group (2012a; 2012b) claims that certain components of its methodological approach determining the failure frequency for spills at Kitimat Terminal and pipeline ruptures were discussed with experts. Yet, the Bercha Group provides no evidence of any consultations with experts in either report and thus it remains unclear how expert judgment was used in the reports and whether or not the experts were independent. With regards to the WorleyParsons report, sections of the pipeline failure frequency assessment underwent expert judgment, particularly failure frequencies for incorrect operations and geohazards, although these frequencies represent only two of the eight hazards for which spill frequencies were developed and there are issues related to the independence of the experts.

The absence of review and validation of findings for the various methodological approaches raises concerns over the credibility, quality, and integrity of spill estimates in the ENGP regulatory application. Validation of results ensures that all critical assumptions and uncertainties are acknowledged and documented, appropriate models, methods, and data are used, and analysis is reproducible by independent parties (IALA 2008).

2. *Lack of third party, independent experts in the review and validation of spill estimates*

A second major deficiency concerns the lack of third party, independent review and validation of the findings that underwent expert review. The two studies to undergo review, i.e. DNV's marine shipping QRA and the WorleyParsons semi-quantitative risk analysis, were evaluated by experts affiliated with both organizations. According to IALA (2008), third party reviewers such as universities and government agencies should assess technical documentation to confirm the integrity of the analysis and contribute credibility to the results.

In their attempt to identify hazards that affect tanker incident frequencies, DNV consulted with local experts in marine transportation on the BC coast (Brandsæter and Hoffman 2010 p. 4-40) and held meetings and interviews with some local stakeholders (Brandsæter and Hoffman 2010 p. 4-46). Once local stakeholders identified hazards in the workshop, experts evaluated hazards of the proposed tanker routes that would be used by ENGP. However, the four experts evaluating hazards consisted of three DNV employees and one employee of WorleyParsons, a consultant hired by Enbridge (Brandsæter and Hoffman 2010 p. 4-44). DNV then incorporated the findings of the hazard identification process into tanker incident frequencies by scaling world average frequencies in order to represent the BC study area. DNV held another workshop where it conducted a peer review to validate the findings of the process to determine appropriate local scaling factors but the review and validation of local scaling factors lacked independence. Two of the five experts involved in the review authored the marine shipping QRA submitted by DNV (Brandsæter and Hoffman 2010 p. 5-52), while one reviewer was at one time a Principal Consultant with DNV Maritime Solutions (DNV 2008), and another reviewer is affiliated with DNV (DNV 2004).

The WorleyParsons report examining risks of a pipeline spill also uses expert review that lacks independence. WorleyParsons contracted AMEC to determine the failure frequency of geohazards such as rock falls, stream flow and erosion, and avalanches, and AMEC uses expert judgment to assess the likelihood of a pipeline spill from geohazards (AMEC 2012 p. 2). Three of the four expert panel members are affiliated with the organizations that either authored the report or directly provided analysis for the report (AMEC 2012 p. 6). Similarly, Dynamic Risk Assessment Systems, which completed analysis for the WorleyPasons study, conducted a workshop to determine data requirements for estimating spill likelihood. Every attendee at the workshop was either a representative of Enbridge, AMEC, or WorleyParsons (DRAS 2012 p. 2).

In summary, the expert review and validation of findings undertaken by DNV and WorleyParsons lack independence. We do not question either the expertise or integrity of individuals that participated in the review, we simply emphasize that there is a lack of third party, independent review and validation of spill estimates for the ENGP.

*Evaluation: There are two major deficiencies related to the validity criterion and thus this criterion is only **not met**.*

Risk Acceptability

Risk Acceptability: Stakeholders identify and agree on acceptable levels of risk in a participatory, open decision-making process and assess risk relative to alternative means of meeting project objectives.

Methods estimating spill return periods in the ENGP regulatory application contain three major deficiencies related to the risk acceptability criterion:

1. Failure to define risk acceptability in terms of the needs, issues, and concerns of stakeholders potentially impacted by the project

The methodological approaches in the ENGP regulatory application all define risk in technical terms. Risk acceptability in the marine shipping QRA has an implicit technical definition that compares spill forecasts for the ENGP derived from historical international data with spill frequencies representative of the 'world average'. DNV compares the unmitigated return period of 79 years for oil/condensate spills to the international spill return period of 74 years and claims that risk "is slightly better than the world average" and that the risk "...may be acceptable compared to existing international operations…" (Brandsæter and Hoffman 2010 p. 7-116)[23]. Risk analyses completed by the Bercha Group (2012a; 2012b; 2012c) and WorleyParsons also fail to adequately assess and define risk acceptability in terms of the needs, issues, and concerns of stakeholders potentially impacted by the project. The Bercha Group studies all define risk acceptability based in part on an algorithm that includes several variables such as the probability of an individual experiencing fatality and the probability of an oil spill from an accident, among others. The studies then compare the results of the algorithm to pre-determined levels of risk acceptability to determine whether or not the risk is significant. Similarly, the WorleyParsons report determines the significance of a threat or hazard in terms of data availability and quality, whereby threats or hazards that cause pipeline failure are assessed as significant or insignificant depending on historical data. Finally, Enbridge does not discuss nor define acceptable levels of risk in *Volume 7B* for the likelihood of pipeline spills, which implies that all levels of risk from pipeline spills are acceptable. A technical definition of risk limits risk analysis to data, methods, and assumptions of the analysts preparing the assessment and fails to incorporate the goals, objectives, and concerns of stakeholders potentially impacted by risk.

2. Failure to effectively consult with stakeholders to determine a level of acceptable risk for tanker, terminal, and pipeline spills

Technical information cannot provide the basis for determining acceptable levels of risk (BC MoELP 2000). Indeed, risk acceptability must materialize from an open dialogue with stakeholders that builds trust and provides confidence in the results (IALA 2008). Determining acceptable levels of risk should be an iterative process

[23] The unmitigated return period of 79 years referenced by DNV on p. 7-116 of Brandsæter and Hoffman (2010) is inconsistent with the unmitigated return period of 78 years referenced on pages 7-107, 1-108, and page 137 of Brandsæter and Hoffman (2010).

that begins with stakeholder consultations early in the process and continues throughout the process to address any residual risk after appropriate mitigation measures have been proposed (IALA 2008). If stakeholders cannot agree on acceptable levels of risk, the proposed activity may need to be abandoned (IALA 2008). Furthermore, the magnitude of adverse impacts is an important consideration that affects risk acceptability. Acceptable risk for a major oil spill will likely be lower than the risk for a smaller spill that causes less significant impacts and may be lower than the risk accepted in other jurisdictions if the attitudes of those impacted are more risk averse.

Stakeholders have not collectively defined and agreed on acceptable levels of risk associated with ENGP tanker, terminal, and pipeline operations. In the marine shipping QRA, DNV consults local experts familiar with marine transportation on the BC coast to identify the influence of local hazards on spill frequencies (Brandsæter and Hoffman 2010 p. 4-40) and holds local meetings and interviews with some local stakeholders to discuss shipping routes, local hazards, and conditions that should be included in the analysis (Brandsæter and Hoffman 2010 p. 4-46). Yet, identifying hazards and their potential risks is not equivalent to determining an acceptable level of risk agreed on by all stakeholders potentially impacted by a spill. Similarly, there is no discussion of any stakeholder consultations in *Volume 7B*, the Bercha Group (2012a; 2012b; 2012c) studies, or the WorleyParsons report, suggesting that stakeholder concerns are not included in defining risk acceptability.

3. Inadequate assessment and comparison of risks associated with project alternatives

A third major deficiency concerns Enbridge's inadequate approach to identifying and comparing alternative approaches to meeting the objective of the ENGP, which is "…to provide access for Canadian oil to large and growing international markets, comprising existing and future refiners in Asia and the United States West Coast" (Enbridge 2010b Vol. 1 p. 1-3). In its evaluation of alternatives, Enbridge fails to justify the ENGP in its proposed configuration, fails to adequately consider risks associated with alternative project configurations, and does not examine and compare risks associated with possible project alternatives beyond simply reconfiguring the ENGP.

In *Volume 1* of its regulatory application, Enbridge outlines several alternative locational configurations of the ENGP prior to selecting the ENGP in its current configuration but provides insufficient information supporting the preferred option. According to Enbridge (2010b Vol. 1 p. 4-3), it considered different locations near Edmonton and Fort McMurray for the inland pipeline terminus in Alberta and examined marine terminals in numerous locations, eventually narrowing candidate sites to Prince Rupert and Kitimat. Enbridge determined that a pipeline terminus near Edmonton and a marine terminal in Kitimat were the preferred alternatives based on evaluative criteria that includes project lifecycle costs, acceptability to shippers, suitability for tankage, safety of tanker operations, constructability of project infrastructure, construction and operation safety, and the likelihood that environmental and socioeconomic interests are affected (Enbridge 2010b Vol. 1. p. 4-1). However, Enbridge fails to provide adequate justification that each alternative was evaluated according to its criteria and omits any detailed comparison of project alternatives required to identify the preferred alternative.

The assessment of alternatives also fails to explicitly evaluate and consider spill probabilities for tanker, terminal, and pipeline spills for each alternative project configuration along with the magnitude of corresponding impacts should a spill occur. Enbridge consulted analysis completed by Fisheries and Oceans Canada in the 1970s that examines the potential effects of oil spills at 11 west coast ports prior to narrowing down marine terminal options to Kitimat and Prince Rupert (Enbridge 2010b Vol. 1 p. 4-3). Nevertheless, Enbridge's assessment represents an inadequate comparison of risks associated with each alternative terminal site that fails to assess and compare the likelihood of tanker and pipeline spills in a comprehensive manner.

On a broader scale, Enbridge does not identify nor compare viable alternatives that meet the stated purpose of the project beyond simply reconfiguring component parts of the ENGP. Realistic project alternatives should be identified, evaluated, and compared and the analysis should include a risk profile for each alternative that enables a comparison of the risks of each candidate project. There are viable alternatives to shipping crude oil from the Western Canada Sedimentary Basin to market that involve no risk from oil tanker spills (Gunton and Broadbent 2012a) and thus determining risk acceptability for tanker spills can be eliminated. A comprehensive comparison of the various project alternatives ensures that decision-makers have adequate information to determine the project that satisfies the public interest of all Canadians while minimizing environmental, cultural, social, and economic risks. Enbridge has not completed such a comparison.

*Evaluation: There are three major deficiencies related to the criterion for risk acceptability and thus this criterion is **not met**.*

4.1. Summary of Qualitative Assessment of Spill Estimates for the ENGP

Table 22 summarizes the results of our evaluation of the methodological approach used to determine spill return periods for the ENGP. Our analysis determined that **none** of the seven best practice criteria have been met in the ENGP regulatory application. The analysis also revealed a total of 28 major deficiencies in the approaches estimating ENGP tanker, terminal and pipeline spills. Based on our analysis, the information presented by Enbridge in the regulatory application for the ENGP does not accurately and effectively communicate the likelihood of adverse environmental effects resulting from a spill required under *CEAA*.

Table 22: Results for the Qualitative Assessment of Spill Estimates for the ENGP

Criterion	Major Deficiencies	Result
Transparency *Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk*	*1.* Lack of supporting evidence for LRFP tanker incident frequency data *2.* Insufficient evidence supporting conditional probabilities for tanker spills *3.* Limited transparency in the application of local scaling factors to the BC study area *4.* Lack of information comparing incident frequencies at Kitimat Terminal to marine terminals in Norway *5.* Lack of transparency in documenting how mitigation measures will reduce the likelihood of tanker and terminal spills *6.* Inadequate evidence supporting the reduction of spill frequencies for pipeline operations	**Not Met**
Replicability *Documentation provides sufficient information to allow individuals other than those who did the original analysis to obtain similar results*	Insufficient proprietary data and information required to replicate: *7.* Incident frequencies for tanker accidents *8.* Scaling factors for ENGP routes *9.* Probabilities and spill volume estimates for tanker spills, *10.* Mitigation measures for tanker and terminal operations *11.* Pipeline incident frequencies	**Not Met**
Clarity *Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision making*	*12.* Failure to effectively communicate the probability of spills over the life of the project *13.* Failure to combine estimates for tanker, terminal, and pipeline spills to present a single spill estimate for the entire project *14.* Failure to determine the likelihood of all spill size categories that can have a significant adverse environmental impact *15.* Lack of clear communication of spill estimates generated in detailed technical data reports in the main ENGP application *16.* Failure to address the effective implementation of mitigation measures that reduce risk	**Not Met**
Reasonableness *The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment*	*17.* Inappropriate definition of the study area to estimate spill return periods for tanker operations *18.* Reliance on tanker incident frequency data that underreport incidents by between 38 and 96%. *19.* Potential double-counting of mitigation measures for LRFP tanker incident data *20.* Inadequate consideration of the corrosiveness of diluted bitumen associated with internal corrosion that may increase spill probability *21.* Failure to consider different vessel characteristics in tanker incident frequencies	**Not Met**
Reliability *Appropriate analytical methods explicitly describe and evaluate sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk*	*22.* Failure to provide confidence intervals that communicate uncertainty and variability in spill estimates for tanker, terminal, and pipeline operations *23.* Failure to complete an adequate sensitivity analysis that effectively evaluates uncertainty associated with spill estimates	**Not Met**
Validity *Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis*	*24.* Inadequate expert review and validation of spill estimates for tanker, terminal, and pipeline operations *25.* Experts in the review and validation of spill estimates lack independence and third-party status	**Not Met**
Risk Acceptability *Stakeholders identify and agree on acceptable levels of risk in a participatory, open decision-making process and assess risk relative to alternative means of meeting project objectives*	*26.* Failure to define risk acceptability in terms of the needs, issues, and concerns of stakeholder potentially impacted by the project *27.* Failure to effectively consult with stakeholders to determine a level of acceptable risk for tanker, terminal, and pipeline spills *28.* Inadequate assessment and comparison of risks associated with project alternatives	**Not Met**

5. Extended Sensitivity Analysis for ENGP Spill Estimates

In this section we undertake a sensitivity analysis to assess the impact of the weaknesses in the methodological approach used to estimate return periods for the ENGP. We caution that our sensitivity analysis does not attempt to addresses all the weaknesses identified in the qualitative assessment. Instead, we demonstrate the impact of different assumptions on spill return periods for ENGP tanker, terminal, and pipeline operations.

5.1. Sensitivity Analysis for Spill Return Periods for Tanker Operations

Our extended sensitivity analysis for ENGP tanker operations examines effects of the following input parameters on unmitigated and mitigated return periods for an oil or condensate spill:

- Testing the combined impact of the four sensitivity parameters identified by DNV in its sensitivity analysis
- Using incident frequencies derived from LRFP data without scaling for BC conditions, thus assuming that BC marine spill risk factors for ENGP tanker traffic conform to the 'world average'
- Increasing conditional probabilities by five percentage points
- Increasing tanker traffic to transport pipeline throughput of 1,125 kbpd (850 kbpd of oil and 275 kbpd of condensate)
- Increasing tanker traffic to represent replacing VLCCs with smaller Suezmax and Aframax tankers to transport throughput of 1,125 kbpd of oil and condensate
- Testing the combined effect of the parameters used in our extended sensitivity analysis.

We follow a similar methodological approach as DNV in order to compare the results of our sensitivity analysis with the sensitivity analysis for tanker spill return periods in the marine shipping QRA. However, one area where our analysis differs is the treatment of tanker traffic. In its sensitivity analysis, DNV compares the relative difference between routes by assuming that 220 tankers travel each route every year. Our sensitivity analysis uses the forecast traffic distribution identified by DNV for tanker traffic along each route. Thus, return periods in our extended sensitivity analysis compare to the unmitigated and mitigated spill return periods of 78 years and 250 years determined by DNV in the marine shipping QRA that reflect forecast traffic on each route. We have done this to simplify the presentation of findings by showing them for one route as opposed to three routes. Another area in which our sensitivity analysis differs from that of DNV is the direction of changes to input parameters. Our analysis only examines changes to input parameters that reduce return periods, thereby increasing the likelihood of a spill. We recognize that additional sensitivity analysis should be completed on the range of input parameters to determine their effect on spill return periods.

Sensitivity 1: Combined Parameters from the DNV Sensitivity Analysis

The first sensitivity analysis combines the four sensitivity parameters identified by DNV in its sensitivity analysis. We examine the collective effect of an increase to local scaling factors for powered and drift grounding by 20%, an increase in scaling factors ranging from 0% to 50% for traffic that affects collision frequency, an increase in the number of tankers calling at Kitimat to 250 per year, and an extension of segments 5 and 8 to 200 nm. Combining sensitivity parameters significantly reduces return periods to 56 years and 171 years for unmitigated and mitigated spills, respectively (Table 23). Our analysis does not consider potential synergies among the four parameters that may further decrease spill return periods.

Table 23: Sensitivity Analysis Combining Sensitivity Parameters Identified by DNV

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline	78	250
Combined Sensitivities	56	171

Source: Based on calculations from Brandsæter and Hoffman (2010).

Sensitivity 2: Unscaled Incident Frequencies

A second sensitivity analysis examines the effect of local scaling factors on unmitigated and mitigated spill return periods for oil or condensate spills by using unscaled incident frequencies. We assume all scaling factors for each incident type are set to 1.0, which implies that tanker operations associated with the ENGP are consistent with the 'world average' that DNV claims is representative of LRFP data (Brandsæter and Hoffman 2010 p. 5-51). Based on this assumption, return periods decrease significantly compared to the baseline, particularly mitigated return periods that decrease over 150 years from 250 years to 83 years under 'world average' conditions for (Table 24).

Table 24: Sensitivity Analysis based on Unscaled Incident Frequencies

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline	78	250
Unscaled Frequencies	54	83

Source: Based on calculations from Brandsæter and Hoffman (2010).

Sensitivity 3: Increased Conditional Probabilities

We examine the effect of changes in conditional probabilities on spill return periods. In the consequences assessment, DNV fails to provide evidence to support the values assigned for each incident type. To test the sensitivity of conditional probabilities on return periods, we increase conditional spill probabilities by five percentage points for grounding, collision, and fire/explosion incidents (Table 25).

Table 25: Five-Percentage Point Increase in Conditional Probabilities for Sensitivity Analysis

Incident Type	Baseline Conditional Probabilities		Increased Conditional Probabilities	
	Laden	In Ballast	Laden	In Ballast
Grounding	32.7%	6.4%	37.7%	11.4%
Collision	19.1%	2.6%	24.1%	7.6%
Foundering*	100%	100%	n/a	n/a
Fire/Explosion	27.0%	7.6%	32.0%	12.6%

Source: Based on calculations from Brandsæter and Hoffman (2010).
* DNV assumes that foundering incidents result in a 100% loss and thus conditional probabilities cannot increase further.

We estimate spill return periods by multiplying increased conditional probabilities by scaled incident frequencies, tanker traffic distribution and distances for each route. As shown in Table 26, the return period for an unmitigated oil or condensate spill decreases as much as 16 years from 78 years to 62 years, while the return period for a mitigated oil/condensate spill decreases 54 years compared to the baseline.

Table 26: Sensitivity Analysis for Increased Conditional Probabilities by Five Percentage Points

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline	78	250
Increased Conditional Probabilities	62	196

Source: Based on calculations from Brandsæter and Hoffman (2010).

Sensitivity 4: Increased Tanker Traffic to Transport Pipeline Throughput of 1,125 kbpd

DNV examines an increase in tanker traffic to 250 tankers per year but does not provide any rationale for restricting the sensitivity to this number. A more realistic approach is to set traffic increases to the level required to transport increased oil and condensate pipeline throughput equivalent to the expansion scenario identified by Enbridge in its response to *Information Request No. 3*. In its response, Enbridge outlines a four-phase expansion of oil pipeline capacity to 850 kbpd and condensate pipeline expansion to 275 kbpd (see Table 27) that includes additional pump stations and infrastructure required to support increased throughput (Enbridge 2010b Information Request No. 3 p. 5). Under the expansion scenario, total combined throughput of both oil and condensate pipelines would total 1,125 kbpd, which would require approximately 237 oil tankers and 94 condensate tankers. The increase in tanker traffic from 220 to 331 tankers per year under Enbridge's phased expansion represents a 50% increase in tanker traffic.

Table 27: Potential Expansion Scenario of Oil and Condensate Pipelines

Pipeline Throughput	Phase I (kbpd)	Phase II (kbpd)	Phase III (kbpd)	Phase IV (kbpd)
Oil	525	600	750	850
Condensate	193	250	275	n/a

Source: Enbridge (2010b Information Request No. 3 p. 9-10).

Table 28 presents unmitigated and mitigated spill return periods for tanker traffic required to transport increased oil and condensate throughput of 1,125 kbpd. We assume that although the number of tankers increases to 331 per year, the proportion of tankers required to transport 1,125 kbpd remains the same for each route as the distribution identified by DNV (See Appendix A for tanker traffic per route). Return periods decrease 26 years for unmitigated oil/condensate spills and 81 years for mitigated spills when tanker traffic increases to transport ENGP throughput of 1,125 kbpd.

Table 28: Sensitivity Analysis for Tankers Transporting 1,125 kbpd

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline	78	250
1,125 kbpd (331 Tankers)*	52	169

Source: Based on calculations from Brandsæter and Hoffman (2010).
* ENGP throughput of 1,125 kbpd requires 237 tankers to transport 850 kbpd and 94 tankers to transport 275 kbpd of condensate.

Sensitivity 5: Replacing VLCCs with Smaller Suezmax and Aframax Tankers to Transport 1,125 kbpd of Oil and Condensate

In the consequence assessment, DNV acknowledges increased risk associated with using a larger number of lower capacity tankers to transport the same amount of cargo (Brandsæter and Hoffman 2010). However, the sensitivity analysis in the marine shipping QRA does not provide estimates of spill return periods associated with using smaller Suezmax and Aframax tankers instead of VLCCs. According to our calculations, the overall tanker fleet would increase 22% from 220 tankers (149 oil and 71 condensate) to 268 tankers per year (197 oil and 71 condensate) if smaller Suezmax and Aframax tankers replace VLCCs. Since the previous sensitivity analysis for the expansion scenario already tests the effects of an increase in tanker traffic, we combine the foregone use of VLCCs with the expansion scenario and estimate the effect on spill return periods.

The scenario in which Suezmax and Aframax tankers transport 1,125 kbpd requires a total of 412 tankers per year to transport 850 kbpd of oil (318 tankers) and 275 kbpd of condensate (94 tankers). We assume that the proportion of Suezmax, and Aframax tankers remains the same as the distribution identified by DNV, although the number of tankers increases in order to transport the same amount of oil and condensate in the absence of VLCCs. A shown in Table 29, the increase in traffic associated with the foregone use of VLCCs under the expansion scenario decreases the return period for an unmitigated oil or condensate spill by 35 years and decreases the mitigated oil/condensate spill return period by 108 years.

Table 29: Sensitivity Analysis for Smaller Tankers Transporting Throughput of 1,125 kbpd

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline	78	250
No VLCCs at 1,125 kbpd (412 Tankers)*	43	142

Source: Based on calculations from Brandsæter and Hoffman (2010).
* ENGP throughput of 1,125 kbpd without the use of VLCCs requires 318 tankers to transport 850 kbpd of oil and 94 tankers to transport 275 kbpd of condensate.

Sensitivity 6: Aggregating Parameters of the Extended Sensitivity Analysis

Similar to combining sensitivity parameters for the sensitivity analysis completed by DNV, we aggregate our sensitivity parameters into a single parameter to examine the combined effects on return periods. We combine the following parameters of our extended sensitivity analysis:

- Unscaled incident frequencies derived from LRFP data that assume oil/condensate spills associated with ENGP tanker traffic conform to the 'world average'
- Increased tanker traffic to 412 tankers per year as a result of increased throughput of 1,125 kbpd (850 kbpd of oil and 275 kbpd of condensate) and the replacement of VLCCs with smaller Suezmax and Aframax tankers
- Increased conditional probabilities by five percentage points.

Combining these parameters decreases the return period for an unmitigated oil/condensate spill 55 years to one spill every 23 years (Table 30). The return period for a mitigated oil or condensate spill decreases significantly by 216 years from a baseline of 250 years to 34 years when we combine the parameters of our extended sensitivity analysis.

Table 30: Sensitivity Analysis Aggregating Parameters from the Extended Sensitivity Analysis

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline	78	250
Aggregate Parameters	23	34

Source: Based on calculations from Brandsæter and Hoffman (2010).

5.2. Sensitivity Analysis for Spill Return Periods for Operations at Kitimat Terminal

DNV did not complete a sensitivity analysis for oil or condensate spills at Kitimat Terminal. To address this deficiency, we conduct a sensitivity analysis for marine terminal operations based on a replication of spill return periods for oil and condensate tankers accessing Kitimat Terminal. Our sensitivity analysis uses the methodology and data presented by DNV in its marine shipping QRA. DNV presents return periods for small and medium size oil or condensate spills and uses spill size categories from the International Tanker Owners Pollution Federation where a small spill is less than 10 m^3 and a medium spill ranges between 10 and 1,000 m^3. Spill sizes for this sensitivity analysis represent small or medium spills (i.e. spills less than 1,000 m^3), which DNV refers to as any size spills (Brandsæter and Hoffman 2010 p. 136).

The focus of our sensitivity analysis is on cargo transfer operations since, according to DNV, loading and unloading operations present the greatest chance of a spill (Brandsæter and Hoffman 2010). We examine changes in two key parameters associated with cargo transfer operations.

Sensitivity 1: Increased Tanker Traffic to Transport Pipeline Throughput of 1,125 kbpd

We increase annual tanker traffic 50% from 220 tankers to 331 tankers required to transport increased pipeline throughput of 1,125 kbpd (237 tankers required to transport 850 kbpd of oil and 94 tankers required to handle 275 kbpd of condensate). An increase to 331 tankers per year decreases the return period for an unmitigated oil/condensate spill of any size by 10 years and decreases the mitigated return period by 21 years (Table 31).

Table 31: Sensitivity Analysis for Increased Marine Terminal Throughput of 1,125 kbpd

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline Cargo Transfer Operations	29	62
1,125 kbpd (331 Tankers)*	19	41

Source: Based on calculations from Brandsæter and Hoffman (2010).
* ENGP throughput of 1,125 kbpd requires 237 tankers to transport 850 kbpd of oil and 94 tankers to transport 275 kbpd of condensate.

Sensitivity 2: Replacing VLCCs with Smaller Suezmax and Aframax Tankers to Transport 1,125 kbpd of Oil and Condensate

For the second parameter, we calculate the effect of increased tanker traffic on spill return periods at the marine terminal if smaller Suezmax and Aframax tankers replace VLCCs in the transportation of 1,125 kbpd of oil and condensate. This scenario requires 318 Suezmax and Aframax oil tankers to replace the fleet of 237 oil tankers inclusive of VLCCs required to transport 850 kbpd of oil, while condensate tankers remain constant at 94 tankers per year in order to transport 275 kbpd of condensate[24]. Compared to baseline conditions of 220 tankers, the return period for an oil/condensate spill decreases 14 years for an unmitigated spill and decreases 29 years for a mitigated spill when 412 Suezmax and Aframax tankers transport 1,125 kbpd (Table 32).

Table 32: Sensitivity Analysis for Smaller Tankers Transporting Throughput of 1,125 kbpd at the Marine Terminal

Sensitivity Parameter	Return Period (in years)	
	Unmitigated	Mitigated
Baseline Cargo Transfer Operations	29	62
No VLCCs at 1,125 kbpd (412 Tankers)*	15	33

Source: Based on calculations from Brandsæter and Hoffman (2010).
* ENGP throughput of 1,125 kbpd without the use of VLCCs requires 318 tankers to transport 850 kbpd of oil and 94 tankers to transport 275 kbpd of condensate.

5.3. Sensitivity Analysis for Spill Return Periods for Pipeline Operations

Enbridge did not complete a sensitivity analysis for spill return periods for the crude oil and condensate pipelines between Bruderheim, AB and Kitimat, BC. To examine the

[24] According to Brandsæter and Hoffman (2010 p. 7-105), no VLCCs are expected to transport condensate and thus the foregone use of VLCCs does not affect condensate tanker traffic.

effects of different assumptions on spill likelihood, we use two different data sets to estimate the frequency of oil and condensate pipeline spills for the ENGP:

- Spill data from the Enbridge liquids pipeline system from 2002 to 2010
- Spill data from the NEB for pipebody and operational leaks > 1.5 m^3 between 2000 and 2009.

We caution that the pipeline spill sensitivity is based on historical performance of existing pipelines that may not be representative of the risks associated with the ENGP.

Sensitivity 1: Enbridge Pipeline Spill Data from 2002 to 2010

We estimate return periods for the ENGP using spill frequency data for the number of spills per annual volume of liquid shipped on the Enbridge liquids pipeline system. According to data submitted by Enbridge (2012a) in the regulatory review process for the ENGP, a total of 608 reportable spills occurred on the Enbridge liquids pipeline system between 2002 and 2010 releasing an average of 26 m^3 (nearly 162 bbl) per spill (Table 33).

Table 33: Historical Spill Data for the Enbridge Pipeline System (2002 - 2010)

Year	Annual Volume Shipped (in barrels)	Number of Spills	Spill Volume (m^3)	Spills per Barrel Shipped*	Liquid Released per Spill* (m^3)
2002	733,440,396	46	2,334	6.27E-08	51
2003	867,686,223	58	1,014	6.68E-08	17
2004	1,123,230,798	64	495	5.70E-08	8
2005	1,060,531,358	70	1,562	6.60E-08	22
2006	1,198,602,588	62	864	5.17E-08	14
2007	1,199,657,322	59	2,187	4.92E-08	37
2008	1,256,268,675	80	426	6.37E-08	5
2009	1,333,947,614	89	1,329	6.67E-08	15
2010	1,487,709,454	80	5,425	5.38E-08	68
Total	**10,261,074,428**	**608**	**15,638**	**5.93E-08**	**26**

Source: Enbridge (2012a).
* Calculated from Enbridge (2012a).

Based on the spill frequency of 5.93E-08 per barrel shipped and proposed shipments of 525 kbpd of crude oil and 193 kbpd of condensate for the ENGP, over 15 oil and condensate spills could occur from the ENGP in any given year (Table 34). The over 15 spills could release an average of 399 m^3 (2,512 bbl) of oil and condensate per year once the ENGP becomes operational. Thus Enbridge's own data shows that the return period for a crude oil or condensate spill is less than one year.

Table 34: Sensitivity Analysis for ENGP Pipelines Using Spill Data for the Enbridge Liquids Pipeline System

Type of Pipeline	Spill Frequency (spills per bbl shipped)	Number of Spills for ENGP (per year)	Spill Volume (m^3)	Return Period (in years)
Crude Oil	5.93E-08	11.4	292	0.1
Condensate		4.2	107	0.2
Crude Oil and Condensate Pipelines		**15.5**	**399**	**0.1**

Source: Calculated from Enbridge (2012a).
Note: We calculate the number of spills based on crude and condensate deliveries of 525 kbpd and 193 kbpd, respectively.

Sensitivity 2: Unmitigated NEB Pipeline Leak Data from 2000 to 2009

We estimate spill frequency for the ENGP based on data from the NEB pipeline system between 2000 and 2009, which represents pipebody and operational leaks. A pipebody leak is any leak from the body of the pipe and includes cracks and pinholes (NEB 2011 p. 13) and operational leaks are leaks from pipeline components such as valves, pumps, and storage tanks (NEB 2011 p. 15). The NEB uses a spill size classification of > 1.5 m^3 (9 bbl) for pipebody and operational leaks. Table 35 contains a history of pipebody liquid leaks from 2000 to 2009, which is the only available data from the NEB[25].

Table 35: Historical NEB Pipebody and Operational Leak Data from 2000 to 2009

Year	Length of NEB Liquid Pipeline (km)	Liquid Pipebody Leaks > 1.5 m^3	Liquid Operational Leaks > 1.5 m^3	Total Leaks > 1.5 m^3	Leak Frequency > 1.5 m^3 * (spills per km-year)
2000	13,219	0	2	2	0.00015
2001	16,165	2	4	6	0.00037
2002	14,803	2	9	11	0.00074
2003	15,245	0	1	1	0.00007
2004	15,012	0	5	5	0.00033
2005	14,269	2	3	5	0.00035
2006	15,566	4	7	11	0.00071
2007	14,368	4	4	8	0.00056
2008	15,715	0	6	6	0.00038
2009	14,442	2	4	6	0.00042
Total	**148,804**	**16**	**45**	**61**	**0.00041**

Source: NEB (2011).
* Calculated from NEB (2011).

Based on NEB pipeline leak data and the length of the ENGP oil and condensate pipelines, the annual spill frequency for spills > 1.5 m^3 (9 bbl) is 0.5 spills per pipeline (Table 36), which represents a spill return period of two years for each of the oil and condensate pipelines. If spill frequencies for crude oil and condensate pipelines are

[25] In response to our request for historical annual data on the number of pipe body liquid releases > 1.5 m^3 and the total volume of leaks per year, the NEB stated "...unfortunately we do not have historical (pre-2000) data analyzed in this way. To perform the requested analysis of data older than 2000 would require weeks of work, as we would need to physically read and analyze each individual investigation report in order to determine if it met the requested criteria and then compile the data from there." (Caza 2012).

combined, the NEB data suggests that a spill > 1.5 m^3 could occur every year the Northern Gateway Project is in operation.

Table 36: Sensitivity Analysis for ENGP Pipelines Using NEB Data for Leaks >1.5m³

Operating Period	**Spill Frequency** (spills per km-year)	**Number of Leaks >1.5 m³ for ENGP** (per year)	**Return Period** (in years)
Crude Oil	0.00041	0.5	2
Condensate		0.5	2
Crude Oil and Condensate Pipelines		**1.0**	**1**

Source: Calculated from NEB (2011).

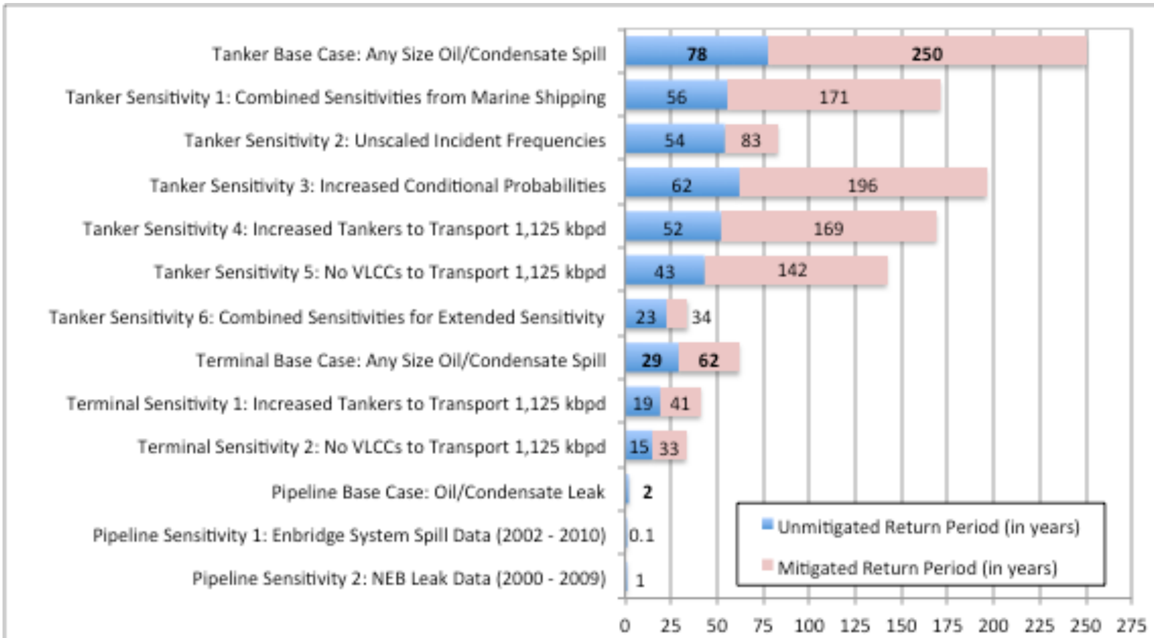
5.4. Summary of Extended Sensitivity Analysis for ENGP Tanker and Terminal Operations

Our extended sensitivity analysis for ENGP tanker, terminal, and pipeline operations assesses the impact of some deficiencies in the methodological approach used in the ENGP application. We address DNV's narrow scope of parameters for its sensitivity analysis, illustrate the impact of a broader range of parameters on spill return periods, and evaluate the sensitivity of mitigated tanker spills, unmitigated and mitigated terminal spills, and pipeline spills. Therefore our extended sensitivity analysis provides a more comprehensive evaluation of the effects of changes in parameters to return periods for ENGP spills. Figure 3 presents a summary of our sensitivity analysis and compares our results with the sensitivity analysis completed in the ENGP application.

Overall, DNV's sensitivity analysis for tanker spills represents small, incremental changes to some of its input parameters that result in small changes to spill return periods. Combined, sensitivity parameters tested by DNV reduce the unmitigated and mitigated return period for oil/condensate spills to 56 years and 171 years, respectively. Alternatively, our sensitivity analysis evaluates changes to key input parameters that result in significant reductions to return periods for unmitigated and mitigated spills of 23 and 34 years, respectively (Figure 3). Significant decreases in return periods as a result of our extended sensitivity analysis illustrate the considerable impact that changes in assumptions have on spill return periods and show the importance of providing transparent documentation justifying assumptions as well as the need for more extensive sensitivity analysis to communicate uncertainties associated with forecasting spills.

Although Enbridge and its consultants fail to complete a sensitivity analysis for terminal and pipeline spills, our sensitivity analysis demonstrates the impact of different assumptions on spill return periods for these operations. For terminal spills, our sensitivity analysis results in an unmitigated spill return period of 15 to 19 years, which compares to the return period of 29 years estimated by DNV for any size oil/condensate terminal spill. For pipeline spills, our sensitivity analysis uses different data inputs based on historical data from Enbridge and the NEB and shows that a pipeline spill could occur at least once per year. These pipeline spill return periods represent a considerable increase in spill likelihood compared to estimates from WorleyParsons (2012) of one oil/condensate pipeline leak every two years.

Figure 3: Summary of Sensitivity Analysis for ENGP Tanker, Terminal, and Pipeline Spills



Note: All return periods represent oil/condensate spills
Source: Based on calculations from Brandsæter and Hoffman (2010); Enbridge (2010b Vol. 7B; 2012); NEB (2011).

6. Application of Oil Spill Risk Analysis Model to the ENGP

The United States developed a comprehensive risk assessment model that it has used to evaluate oil spill risks for US oil and gas exploration and development for several decades. Given the widespread use and acceptance of the US OSRA model, it is useful to apply it to the ENGP to assess spill risk. The following section describes this model and applies it to generate spill probability estimates for ENGP tanker and pipeline operations. The US model is then evaluated with best practice guidelines for risk assessment in order to identify any major deficiencies of the approach to estimating spill probabilities for the ENGP.

6.1. Overview of Oil Spill Risk Analysis Model

The OSRA model was developed in 1975 by the US Department of the Interior (Smith et al. 1982) and is a well-established methodology that the US government uses to estimate oil spill occurrence probabilities, as well as the chances of spills contacting environmental resources. Although there is no legislative requirement to use the OSRA model, concerns related to oil spill prevention and contingency planning following implementation of the Oil Pollution Act of 1990 (U.S. Public Law 101-380, August 18, 1990) have created a sustained interest in estimating oil spill probabilities among all stakeholder groups (Anderson and LaBelle 2000). The Bureau of Ocean Energy Management (BOEM), formerly the Minerals Management Service, examines commercial oil and gas development on the Outer Continental Shelf adjacent to the

United States of America with the OSRA model (Price et al. 2003). The OSRA model is also used by the BOEM to prepare environmental documents pursuant to the *National Environmental Policy Act*, as well as for environmental assessments, consultations for endangered species and fish habitat, oil spill planning and preparedness by the Bureau of Safety and Environmental Enforcement (BSEE) (Anderson et al. 2012), and other federal and state government agencies including the US Fish and Wildlife Service, the National Marine Fisheries Service, and the US Coast Guard (Price et al. 2003). Furthermore, industry uses the OSRA model in the preparation of oil spill contingency plans (Anderson et al. 2012).

The OSRA model has been used in several specific applications in the US Outer Continental Shelf. BOEM typically prepares an environmental impact statement for offshore lease areas and a component of the environmental impact statement is an evaluation of potential oil spill risk over the life of the projects under consideration (Anderson and LaBelle 1990). The US federal government used the OSRA model to examine spill probabilities associated with the development of offshore resources in the Beaufort Sea in northern Alaska (US DOI 1997), Cook Inlet in southern Alaska (US DOI 2003b), and the Gulf of Mexico (US DOI 2002; 2007b), and examined development on the Pacific Outer Continental Shelf off the coast of California (US DOI 2000a), oil and gas development on the Eastern Gulf of Mexico Outer Continental Shelf (US DOI 1998), and other development and exploration activities in the Beaufort Sea (US DOI 2000b; US DOI 2007a). The model continues to be used in US offshore leasing areas at present.

The OSRA model consists of three main components: (1) probability of spills occurring; (2) trajectory simulation of spills, and; (3) combined spill probabilities and trajectory simulations (Smith et al. 1982). The probability assessment developed by the US Department of the Interior uses a per-volume methodology that relies on historical spill occurrences and volume of oil handled. A fundamental component of this forecasting method is defining an appropriate exposure variable, which is defined as a "…quantity related to oil production or transportation which has a precise statistical relationship to spill occurrence" (Smith et al. 1982). Smith et al. (1982) assert that spill occurrence estimates "depend fundamentally on the estimated amount of oil to be produced" (p. 20) and recommend volume due to the variable's simplicity and predictability. Similarly Lanfear and Amstutz (1983) suggest that the volume of oil handled is "… the most practical exposure variable for predicting oil spill occurrences as a Poisson process" (p. 359). More recently, Anderson et al. (2012) and Anderson and LaBelle (2000) support Smith et al. (1982) and Lanfear and Amstutz (1983) in the recommendation of volume as the exposure variable in the OSRA because it satisfies two important criteria: (a) volume is easy to define, and; (b) volume is a quantity that can be estimated based on historical volumes of oil handled[26].

[26] For pipeline spills, Eschenbach et al. (2010) suggest that pipeline-mile years is more directly linked to the probability of oil spills compared to production volume and reason that the probability of a spill from a network of pipelines depends on the length of the pipeline. However, Eschenbach et al. also determine that production volume is an appropriate exposure variable since it passes a goodness of fit test.

The OSRA assumes that spills occur independently of each other as a Poisson process[27]. Spill occurrence conforms to a Poisson process for three reasons: (1) no spill can occur when the volume of oil produced or transported is equal to zero; (2) the record shows that spill events are independent of each other over time and volume, and; (3) the number of events in any interval are Poisson distributed and this process has stationary increments (Anderson et al. 2012; Anderson and LaBelle 2000). Smith et al. (1982) describe the probability (P) of a specific number of spills (n) in the course of handling t barrels where λ is the rate of spill occurrence:

Equation 1: OSRA Model Equation (Poisson Assumption)

$$P(n) = \frac{(\lambda t)^n e^{-\lambda t}}{n!}$$

The above formula bases the rate at which spills occur (λ), which is typically expressed as the mean number of spills per billion barrels (Bbbl) of oil handled, on historic spill occurrence data and the volume of oil produced/transported (Anderson et al. 2012; Anderson and LaBelle 2000). The BSEE collects tanker spill data from the United States Coast Guard and from international sources, and manages a database that provides spill rate data for tanker spills that occur at sea and in port (Anderson et al. 2012). Tanker spill rates are also based on data from the US Department of Commerce, the US Army Corps of Engineers, and British Petroleum's *Statistical Review of World Energy* (Anderson et al. 2012). Anderson et al. (2012) and Anderson and LaBelle (2000) estimate tanker spill rates for spills ≥ 1,000 bbl (159 m^3) because spills of this size are more likely to be reported compared to smaller spills and the historical data are considered more comprehensive than data for spills less than 1,000 bbl. Anderson and LaBelle (2000) estimate spill rates for pipeline systems in Alaska with historical data from the Minerals Management Service and the State of Alaska. Spill rates developed by Anderson et al. (2012) and Anderson and LaBelle (1990; 1994; 2000) have been regularly updated and improved to reflect changes in spill rates over time.

6.2. Spill Probability Estimates for ENGP Tanker Operations

We develop probability estimates for oil and condensate spills for ENGP tanker operations based on the OSRA model[28]. The approach to estimating spill probabilities with the OSRA model includes four main steps:

1. Obtain historical spill rate data

[27] Smith et al. (1982) recognize that this assumption can be questioned particularly in the case that safety standards are improved after a particular spill (i.e. introduction of double hull tankers). However, Smith et al. acknowledge that there is sufficient evidence that a Poisson process provides a reasonable approximation for spill occurrence (Stewart and Kennedy 1978 as cited in Smith et al. 1982).

[28] According to Anderson et al. (2012), spill rates for tanker incidents in international waters and Valdez, Alaska represent crude oil tanker spills. We use crude oil tanker spill rates to approximate condensate tanker spill rates because the condensate-carrying vessels are similar to vessels carrying crude oil and specific incident data for condensate tankers are insufficient. We note that this approach is consistent with that used by DNV in the ENGP regulatory application.

2. Estimate the volume of oil and condensate handled over the operational life of the project being assessed (ENGP)
3. Calculate spill probabilities with the OSRA model in Equation 1 based on data from steps (1) and (2)
4. Complete a sensitivity analysis to examine the effect of changes in inputs to spill probabilities.

Anderson et al. (2012) provide the most recent historical spill rate data for use in the OSRA model for international tanker spills and spills from tankers transporting Alaska North Slope crude oil. As shown in Table 37, spill rates determined by Anderson et al. (2012) range from 0.32 to 0.84 spills per Bbbl for tanker spills ≥ 1,000 bbl (159 m^3) and range from 0.11 to 0.42 spills per Bbbl for spills ≥ 10,000 bbl (1,590 m^3). International spill rates for the largest spill size category identified by Anderson et al. (2012) range between 0.03 and 0.17 for spills ≥ 100,000 bbl (15,900 m^3). Anderson et al. (2012) suggest that regulatory changes in the 1990s requiring double hull tankers are the likely cause of continued declines in tanker spills over time.

Table 37: International and Alaska Oil Tanker Spill Rates

Spill size	Source Data	Time Period	Number of Spills	Volume Transported (Bbbl)	Spill Rate (per Bbbl)
≥ 1,000 bbl (≥ 159 m^3)	International	1974-2008	303	359.9	0.84
		1994-2008	59	185.8	0.32
	Valdez, Alaska	1977-2008	11	15.3	0.72
		1989-2008	4	8.7	0.46
				Range of Spill Rates (per Bbbl)	**0.32 - 0.84**
≥ 10,000 bbl (≥ 1,590 m^3)	International	1974-2008	151	359.9	0.42
		1994-2008	20	185.8	0.11
	Valdez, Alaska	1977-2008	3	15.3	0.20
		1989-2008	1	8.7	0.12
				Range of Spill Rates (per Bbbl)	**0.11 - 0.42**
≥ 100,000 bbl (≥ 15,900 m^3)	International	1974-2008	62	359.9	0.17
		1994-2008	6	185.8	0.03
				Range of Spill Rates (per Bbbl)	**0.03 - 0.17**

Source: Anderson et al. (2012).
Note: Bbbl represents one billion barrels of oil.

In the second step, we estimate the volume of oil and condensate transported by ENGP tanker traffic over the operational life of the project. The amount of crude oil potentially shipped out of Kitimat Terminal is equal to pipeline capacity of 525 kbpd, which equates to approximately 191.6 million barrels per year. Over a 30-year and 50-year operating period, a volume of 525 kbpd represents over 5.7 Bbbl and 9.6 Bbbl, respectively, of oil transported by tankers. The volume of condensate is equal to pipeline capacity of 193 kbpd or 70.4 million barrels per year. Condensate throughput over a 30-year and 50 year period equals 2.1 and 3.5 Bbbl, respectively. These oil and condensate volumes represent the baseline throughput capacities in the ENGP regulatory application.

In the third step, we use spill rates for tanker spills and the volume of oil and condensate transported by ENGP tanker traffic as inputs to the OSRA model (Equation 1) and estimate spill probabilities. Our application of the OSRA model uses the following four spill occurrence rates to determine tanker spill probabilities for the ENGP:

i. Spills in international waters between 1974 and 2008, which represent the entire record of worldwide tanker spills from the BOEM database
ii. Spills in international waters between 1994 and 2008, which represent worldwide spills from modern tanker operations in the last 15 years of the BOEM database
iii. Spills associated with shipments departing Valdez, Alaska between 1977 and 2008, which represent the entire record of tanker spills transporting Alaska North Slope crude oil
iv. Spills associated with shipments departing Valdez, Alaska between 1989 and 2008 that represent the last 20 years of modern tanker traffic transporting Alaskan crude oil.

As shown in Table 38, probabilities for ENGP tanker spills are high over a 30-year period at baseline throughput capacities. According to the OSRA model, spill probability for ENGP tanker operations ranges from 84.1% to 99.2% for oil spills ≥ 1,000 bbl, and spill probability increases to between 91.9% and 99.9% for an oil or condensate spill ≥ 1,000 bbl. Probabilities for larger ENGP oil/condensate tanker spills range between 57.9% and 96.3% for spills ≥ 10,000 bbl, and between 21.0% and 73.7% for spills ≥ 100,000 bbl over a 30-year period. The lower probabilities are based on the 1994 to 2008 international data and given improvements in safety, these lower probabilities are likely more indicative of future spill rates.

Table 38: ENGP Tanker Spill Probabilities based on OSRA Model (30 years)

Spill size	Source Data	Time Period	30-Year Spill Probability (%) Oil	Condensate	Combined
≥ 1,000 bbl (≥ 159 m^3)	International	1974-2008	99.2	83.1	99.9
		1994-2008	84.1	49.1	91.9
	Valdez, Alaska	1977-2008	98.4	78.2	99.7
		1989-2008	92.9	62.2	97.3
		Range	**84.1 - 99.2**	**49.1 - 83.1**	**91.9 - 99.9**
≥ 10,000 bbl (≥ 1,590 m^3)	International	1974-2008	91.1	58.8	96.3
		1994-2008	46.9	20.7	57.9
	Valdez, Alaska	1977-2008	68.3	34.5	79.2
		1989-2008	49.8	22.4	61.1
		Range	**46.9 - 91.1**	**20.7 - 58.8**	**57.9 - 96.3**
≥ 100,000 bbl (≥ 15,900 m^3)	International	1974-2008	62.4	30.2	73.7
		1994-2008	15.8	6.1	21.0
		Range	**15.8 - 62.4**	**6.1 - 30.2**	**21.0 - 73.7**

Source: Calculated based on Anderson et al. (2012).

Over a 50 year operating period, the minimum probability for oil spills ≥ 1,000 bbl is 95.3%, which increases to 98.5% for an oil or condensate tanker spill (Table 39). The respective minimum probability for oil/condensate spills ≥ 10,000 bbl and ≥ 100,000 bbl is 76.3% and 32.5%, respectively. Again, the lower probabilities are based on the

1994 to 2008 international data and given improvements in safety, these lower probabilities are likely more indicative of future spill rates.

Table 39: ENGP Tanker Spill Probabilities based on OSRA Model (50 years)

Spill size	Source Data	Time Period	50-Year Spill Probability (%)		
			Oil	Condensate	Combined
≥ 1,000 bbl (≥ 159 m^3)	International	1974-2008	99.9	94.8	99.9
		1994-2008	95.3	67.6	98.5
	Valdez, Alaska	1977-2008	99.9	92.1	99.9
		1989-2008	98.8	80.2	99.8
		Range	**95.3 - 99.9**	**67.6 - 94.8**	**98.5 - 99.9**
≥ 10,000 bbl (≥ 1,590 m^3)	International	1974-2008	98.2	77.2	99.6
		1994-2008	65.1	32.1	76.3
	Valdez, Alaska	1977-2008	85.3	50.6	92.7
		1989-2008	68.3	34.5	79.2
		Range	**65.1 - 98.2**	**32.1 - 77.2**	**76.3 - 99.6**
≥ 100,000 bbl (≥ 15,900 m^3)	International	1974-2008	80.4	45.1	89.2
		1994-2008	25.0	10.0	32.5
		Range	**25.0 - 80.4**	**10.0 - 45.1**	**32.5 - 89.2**

Source: Calculated based on Anderson et al. (2012).

In the fourth step, we complete a sensitivity analysis for the OSRA model by increasing the volume of oil transported from 525 kbpd to 850 kbpd and increasing the volume of condensate from 193 kbpd to 275 kbpd as outlined by Enbridge in its response to an information request (Enbridge 2010b Information Request No. 3). The OSRA model estimates a minimum probability of 94.9% that an oil tanker spill ≥ 1,000 bbl could occur over a 30-year period at a throughput of 850 kbpd of oil. The minimum probability increases to 98.1% for an oil or condensate spill ≥ 1,000 bbl at higher throughput capacities of 850 kbpd of oil and 275 kbpd of condensate (Table 40). The minimum probability for an oil/condensate spill ≥ 10,000 bbl is 74.2% in a 30-year period suggesting a spill of this size could likely occur over the life of the ENGP.

Table 40: Sensitivity Analysis for ENGP Tanker Spill Probabilities at Higher Capacities (30 Years)

Spill size	Source Data	Time Period	30-Year Spill Probability (%)		
			Oil	Condensate	Combined
≥ 1,000 bbl (≥ 159 m^3)	International	1974-2008	99.9	92.0	99.9
		1994-2008	94.9	61.8	98.1
	Valdez, Alaska	1977-2008	99.9	88.6	99.9
		1989-2008	98.6	75.0	99.7
		Range	**94.9 - 99.9**	**61.8 - 92.0**	**98.1 - 99.9**
≥ 10,000 bbl (≥ 1,590 m^3)	International	1974-2008	98.0	71.8	99.4
		1994-2008	64.1	28.2	74.2
	Valdez, Alaska	1977-2008	84.5	45.2	91.5
		1989-2008	67.3	30.3	77.2
		Range	**64.1 - 98.0**	**28.2 - 71.8**	**74.2 - 99.4**
≥ 100,000 bbl (≥ 15,900 m^3)	International	1974-2008	79.4	40.1	87.7
		1994-2008	24.4	8.6	30.9
		Range	**24.4 - 79.4**	**8.6 - 40.1**	**30.9 - 87.7**

Source: Calculated based on Anderson et al. (2012).

Spill probabilities for an ENGP oil/condensate tanker spill increase significantly over a 50-year operating period at higher throughput capacities (Table 41). Indeed, the OSRA model estimates a high likelihood (89.5%) that an oil/condensate spill ≥ 10,000 bbl could occur over the life of the project. For larger spills, The OSRA model estimates there is at least a 46.0% chance that an oil/condensate spill nearly half the size of the Exxon Valdez oil spill of 41,000 m^3 could occur within a 50-year period of the ENGP operating at higher throughput capacities.

Table 41: Sensitivity Analysis for ENGP Tanker Spill Probabilities at Higher Capacities (50 years)

Spill size	Source Data	Time Period	50-Year Spill Probability (%)		
			Oil	**Condensate**	**Combined**
≥ 1,000 bbl (≥ 159 m^3)	International	1974-2008	99.9	98.5	99.9
		1994-2008	99.3	79.9	99.9
	Valdez, Alaska	1977-2008	99.9	97.3	99.9
		1989-2008	99.9	90.1	99.9
		Range	**99.3 - 99.9**	**79.9 - 98.5**	**99.9**
≥ 10,000 bbl (≥ 1,590 m^3)	International	1974-2008	99.9	87.9	99.9
		1994-2008	81.8	42.4	89.5
	Valdez, Alaska	1977-2008	95.5	63.3	98.4
		1989-2008	84.5	45.2	91.5
		Range	**81.8 - 99.9**	**42.4 - 87.9**	**89.5 - 99.9**
≥ 100,000 bbl (≥ 15,900 m^3)	International	1974-2008	92.8	57.4	97.0
		1994-2008	37.2	14.0	46.0
		Range	**37.2 - 92.8**	**14.0 - 57.4**	**46.0 - 97.0**

Source: Calculated based on Anderson et al. (2012).

We note several limitations in our application of the OSRA model to the ENGP. The principal limitation relates to the model's reliance on historical data to estimate future spill rates. As noted, there have been improvements in safety that resulted in a reduction in spill rates over time (Anderson et al. 2012; Anderson and LaBelle 2000) and thus historical rates may not accurately reflect future risk. Tanker spill rates in the future could continue to decline as a result of further mitigation measures and regulatory requirements, remain static due to diminishing returns from previous regulatory and technological improvements, or increase as a result of potential future deregulation or an aging tanker fleet. We do not attempt to predict future tanker spill rates over the operational life of the ENGP. Second, average historical data may not reflect the unique characteristics of the project environment that may affect risk such as unusual hazards or special mitigation measures. We attempt to mitigate this weakness by using tanker spill data from Alaska, which may increase the likelihood that data more accurately reflect the unique risks of the Pacific west coast region. Furthermore, Alaska data for the 1989 to 2008 period represents mitigation measures similar to those proposed for the ENGP such as escort tugs. Third, Anderson et al. (2012) do not estimate confidence intervals for tanker spill rates. Although Anderson and LaBelle (2000) determine 95% confidence intervals for spill rates, the recent update by Anderson et al. (2012) only provides the mean estimate for spill rates. We attempt to address this issue by providing a range of spill probabilities based on different spill occurrence rates.

6.3. Spill Probability Estimates for ENGP Pipeline

We also develop probability estimates for ENGP pipeline spills with the OSRA model. Our approach to estimating pipeline spill probabilities with the OSRA model follows the same approach as that used to determine probabilities for tanker spills.

In the first step, we obtain spill rates from Anderson and LaBelle (2000) based on historical data for the Trans-Alaska Pipeline System and onshore Alaska North Slope crude oil production (Table 42). Between 1977 and 1998, six spills ≥ 500 bbl (80 m^3) and five spills ≥ 1,000 bbl (159 m^3) occurred from the Trans-Alaska Pipeline System, resulting in a spill rate of 0.48 and 0.40, respectively, for every Bbbl moved. A single spill ≥ 500 bbl (80 m^3) associated with the Trans-Alaska Pipeline System occurred between 1985 and 1998 producing a spill rate of 0.12. Anderson and LaBelle (2000) also determine that a single Alaskan North Slope crude oil and condensate spill ≥ 500 bbl occurred from onshore pipelines between 1985 and 1998, yielding a spill rate similar to the Trans-Alaska Pipeline System rate of 0.12 spills for every Bbbl transported.

Table 42: Spill Rates for Pipeline Spills in Alaska based on Anderson and LaBelle (2000)

Spill Size	Source Data	Time Period	Number of Spills	Spill Rate (per Bbbl)
≥ 500 bbl (80 m^3)	Trans-Alaska Pipeline System	1977-1998	6	0.48
		1985-1998	1	0.12
	Alaska North Slope	1985-1998	1	0.12
≥ 1,000 bbl (159 m^3)	Trans-Alaska Pipeline System	1977-1998	5	0.40
		1985-1998	0	-
	Alaska North Slope	1985-1998	0	-

Source: Anderson and LaBelle (2000).

In the second step, we estimate the volume of oil and condensate transported by the Northern Gateway Pipeline over an operating period of 30 to 50 years. Since pipeline spill rates from Anderson and LaBelle (2000) represent oil and condensate, we assume pipeline throughput of 718 kbpd for the ENGP based on oil pipeline volume of 525 kbpd and condensate volume of 193 kbpd. Combined oil and condensate throughput represents 7.9 Bbbl over 30 years and 13.1 Bbbl over 50 years. We also complete a sensitivity analysis examining the effects of increased capacity to 1,125 kbpd (850 kbpd of oil and 275 kbpd of condensate), which equates to approximately 12.3 Bbbl over 30 years and 20.5 Bbbl over 50 years.

In the third step, we use the following two spill occurrence rates from Anderson and LaBelle (2000) to determine a range of probabilities for ENGP pipeline spills ≥ 500 bbl:

i. Spills from the Trans-Alaska Pipeline System between 1977 and 1998, which represent the entire record of pipeline spills from the BOEM database
ii. Spills from the Trans-Alaska Pipeline System and Alaska North Slope pipelines between 1985 and 1998, which represent the most recent record of pipeline spills provided by BOEM.

We input the spill rates for pipeline spills ≥ 500 bbl and the volume of oil transported by the ENGP pipeline in Equation 1 to estimate probabilities for ENGP pipeline spills (Table 43). Over a 30-year operating period at planned throughput capacity, the probability of an ENGP pipeline spill ≥ 500 bbl ranges between 61.1% and 97.7% and the probability increases to between 79.2% and 99.8% over a 50-year operating period.

Table 43: Pipeline Spill Probabilities based on OSRA Model (30 and 50 Years)

Spill Size	Source Data	Time Period	30-Year Spill Probability (%)	50-Year Spill Probability (%)
≥ 500 bbl (80 m^3)	Trans-Alaska Pipeline System	1977-1998	97.7	99.8
	Trans-Alaska Pipeline System / Alaska North Slope	1985-1998	61.1	79.2
		Range	**61.1 - 97.7**	**79.2 - 99.8**

Source: Calculated based on Anderson and LaBelle (2000).

Our sensitivity analysis examines changes in spill probabilities if the volume of oil transported by the pipeline increases 62% to 850 kbpd and the volume of condensate increases 42% to 275 kbpd. Over 30- and 50-year operating periods, the minimum likelihood of a spill ≥ 500 bbl increases to 77.2% and 91.5%, respectively, when pipeline throughput increases to 1,125 kbpd.

Table 44: Sensitivity Analysis for Pipeline Spill Probabilities at Higher Capacities (30 and 50 Years)

Spill Size	Source Data	Time Period	30-Year Spill Probability (%)	50-Year Spill Probability (%)
≥ 500 bbl (80 m^3)	Trans-Alaska Pipeline System	1977-1998	99.7	99.9
	Trans-Alaska Pipeline System / Alaska North Slope	1985-1998	77.2	91.5
		Range	**77.2 - 99.7**	**91.5 - 99.9**

Source: Calculated based on Anderson and LaBelle (2000).

The application of the OSRA model with spill rates from pipeline spills in Alaska to the ENGP has several limitations. First, it assumes that historical pipeline spill data from Alaska is appropriate to estimate future spills for ENGP pipelines, which may have different risks due to different technological, safety, and regulatory standards. The counter argument to this limitation is that available historical spill data from Enbridge's own liquids pipeline system does not indicate improvements in pipeline safety between 1998 and 2010 and thus there is no rationale for reducing spill rates. Further, a study of spill rates in the US from Eschenbach et al. (2010) determined no significant decline in pipeline spill rates between 1972 and 2005. Another limitation is that the OSRA pipeline data only includes spills ≥ 500 bbl, and therefore excludes a large proportion of smaller spills (i.e. spills less than 500 bbl) that may cause environmental, economic, and sociocultural damage. Finally, Anderson and LaBelle (2000) do not provide confidence intervals for pipeline spills.

6.4. Summary of ENGP Spill Probabilities Estimated with OSRA Model

The summary of spill probabilities for ENGP tanker and pipeline spills calculated with the OSRA model in Table 45 shows that oil/condensate spill probabilities for the ENGP are high, particularly for spills ≥ 1,000 bbl. Indeed, the OSRA model estimates that the minimum probability of a tanker spill ≥ 1,000 bbl over the 30- and 50-year life of the ENGP is 91.9% and 98.5%, respectively. For spills ≥ 10,000 bbl, the minimum probability of a spill over the life of the ENGP is 57.9%, which increases to 89.5% when the ENGP operates over a 50-year period at higher throughput capacities. Based on the OSRA, there is at least a 32.5% chance that a spill nearly half the size of the Exxon Valdez oil spill of 41,000 m^3 could occur within a 50-year period of the ENGP operating at its planned throughput capacity and the minimum probability of a spill increases to 46.0% if the ENGP ships higher volumes of oil and condensate over a 50-year period. Table 45 also presents an overall spill probability for the entire ENGP, which ranges between 96.8% and 99.9% over the life of the project[29]. Thus, the OSRA model estimates that there is a very high likelihood that either a tanker spill ≥ 1,000 bbl or a pipeline spill ≥ 500 bbl could occur during ENGP operations.

Table 45: Summary of Tanker and Pipeline Oil/Condensate Spill Probabilities for the ENGP

Type and Size Spill	30-Year Spill Probability (%)		50-Year Spill Probability (%)	
	718 kbpd*	1,125 kbpd**	718 kbpd*	1,125 kbpd**
Tanker Spill				
≥ 1,000 bbl (≥ 159 m^3)	91.9 - 99.9	98.1 - 99.9	98.5 - 99.9	99.9
≥ 10,000 bbl (≥ 1,590 m^3)	57.9 - 96.3	74.2 - 99.4	76.3 - 99.6	89.5 - 99.9
≥ 100,000 bbl (≥ 15,900 m^3)	21.0 - 73.7	30.9 - 87.7	32.5 - 89.2	46.0 - 97.0
Pipeline Spill*				
≥ 500 bbl (≥ 80 m^3)	61.1 - 97.7	77.2 - 99.7	79.2 - 99.8	91.5 - 99.9
Tanker or Pipeline Spill				
See Note	96.8 - 99.9	99.6 - 99.9	99.7 - 99.9	99.9

* Represents oil volume of 525 kbpd and condensate volume of 193 kbpd (total of 718 kbpd),
** Represents oil volume of 850 kbpd and condensate volume of 275 kbpd (total of 1,125 kbpd).
Note: Combined tanker and pipeline spill calculated based on the following spill probabilities: (1) oil/condensate spill probabilities for tanker spills ≥ 1,000 bbl and; (2) oil/condensate spill probabilities for pipeline spills ≥ 500 bbl.

6.5. Evaluation of OSRA Model with Best Practice Criteria for Risk Assessment

Similar to our evaluation of methods used to estimate spill return periods in the ENGP regulatory application, we evaluate the OSRA method with best practice guidelines for risk assessment (see Table 17). We qualitatively assess each criterion according to the four-point scale:

- Fully met: no deficiencies
- Largely met: no major deficiencies
- Partially met: at least one major deficiency
- Not met: two or more major deficiencies

[29] We estimate overall spill probabilities for the ENGP based on: (1) oil/condensate spill probabilities for tanker spills ≥ 1,000 bbl, and (2) oil/condensate spill probabilities for pipeline spills ≥ 500 bbl.

Transparency

Criterion: Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk.

Our application of the OSRA model to the ENGP provides transparency. We clearly summarize and provide supporting evidence for tanker and pipeline spill rates determined by Anderson et al. (2012) and Anderson and LaBelle (2000), volumes for oil and condensate over the operating life of the ENGP, and increases in the volume of oil handled in the sensitivity analysis with reference to Enbridge's phased expansion that could increase the amount of oil handled from 525 kbpd to 850 kbpd and the amount of condensate handled from 193 kbpd to 275 kbpd (Enbridge 2010b Information Request No. 3). Furthermore, we transparently identify weaknesses of the OSRA model applied to the ENGP, which consist of the model's usage of historical data, data from a different, albeit similar geographical area, and the model's limited availability of confidence intervals.

*Evaluation: There are no major deficiencies related to the transparency criterion and thus this criterion is **fully met**.*

Replicability

Criterion: Documentation provides sufficient information to allow individuals other than those who did the original analysis to obtain similar results.

Due to its parsimonious methodology, replicating the OSRA methodology is straightforward as the model requires two major inputs: (1) the volume of oil handled, and; (2) the spill rate based on historical spill occurrence data for various classes of spills. In our application of the OSRA model, we estimate volume data for the ENGP according to the planned volume of hydrocarbon transported in the ENGP regulatory application. We derive spill rates from Anderson et al. (2012) and Anderson and LaBelle (2000), and both studies disclose proprietary data required to replicate historical spill rates for international tanker spills and tanker spills in US waters. Furthermore, Smith et al. (1982) provide a detailed description of how to calculate spill probabilities as a Poisson process for fixed classes of spills with volume of oil handled as the exposure variable (see Equation 1).

*Evaluation: There are no major deficiencies related to the replicability criterion and thus this criterion is **fully met**.*

Clarity

Criterion: Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision-making.

The OSRA method clearly estimates spills as probability of occurrence over the life of the project and probabilities represent various classes of tanker spills at port and at sea, including smaller spills that, according to the US DOI (2003a) can have significant adverse environmental effects (i.e. spills ≥ 1,000 bbl or ≥ 159 m^3). Furthermore, we combine probability estimates for tanker spills and pipeline spills into a single value that effectively communicates spill risk for the entire ENGP.

*Evaluation: There are no major deficiencies related to the clarity criterion and thus this criterion is **fully met**.*

Reasonableness

Criterion: The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment.

The major deficiency in the OSRA method related to reasonableness is the model's reliance on average historical spill rates:

1. ***Historical spill data may not represent similar operating conditions as ENGP tanker and pipeline operations***
   Several observations suggest that historical spill rate data from Anderson et al. (2012) and Anderson and LaBelle (2000) may not reflect the unique characteristics of the ENGP. First, average historical tanker spill data from Anderson et al. (2012), which shows a reduction in spill frequency over time as a likely result of regulatory changes requiring double hull tankers, may not reflect future ENGP tanker operations. Future tanker operations for the ENGP could include increased safety and technological measures such as escort tug operations, enhanced navigation systems, different tanker characteristics and types, and different regulatory standards that further reduce tanker spill rates over the operational life of the project. However, the increasing age of the tanker fleet may offset safety improvements, resulting in an increase in future spill rates. A recent study from Eliopoulou et al. (2011) determines that non-accidental structural failure incident rates are higher for double-hull tankers over the age of 15 years. Thus historical spill rate data may underestimate future spill rates for particular incident types such as non-accidental structural failures, since these types of accidents may become significant after 2020 (Papanikolaou et al. 2009). We avoid any assumptions or speculation about future tanker spill rates. Second, historical spill data may not reflect unique characteristics of the project environment that could affect risk. International spill rate data from Anderson et al. (2012) based on average tanker operations reflect a range of different operating conditions, weather conditions, and maintenance programs, and thus these data may not represent tanker traffic associated with the ENGP that would operate in a region containing potential hazards related to maneuverability, visibility, and meteorological and oceanographic conditions. Similarly, historical spill rate data from the Trans-Alaska Pipeline System and Alaska North Slope crude oil

transportation systems may not reflect the conditions of ecologically sensitive regions that potentially present unique terrain and climactic conditions for the ENGP oil and condensate pipeline. Third, the OSRA model does not consider any increased risk associated with the corrosiveness of diluted bitumen. Given the corrosive threat characteristic of higher sulphur concentrations (Lyons and Plisga 2005) and the higher sulphur content in dilbit (EC OPD 2012), as well as increased internal corrosion rates observed between the Alberta and US pipeline systems, the increased risk associated with transporting dilbit may increase spill occurrence rates for tanker, terminal, and pipeline operations. We do not attempt to adjust spill rate data from Anderson et al. (2012) or Anderson and LaBelle (2000) for any of the aforementioned characteristics unique to ENGP tanker, terminal, and pipeline operations. We note that despite these potential deficiencies, the OSRA model has held up in US courts when it has been challenged (LaBelle 2012).

*Evaluation: There is one major deficiency related to the reasonableness criterion and thus this criterion is **partially met**.*

Reliability

Criterion: Appropriate analytical methods explicitly describe and evaluate sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk.

In the application of the OSRA model to the ENGP, we test the magnitude of uncertainties with a sensitivity analysis of the two input parameters to the model. Our sensitivity analysis examines the effects of an increase in volume of oil handled, and we use various spill rates based on different historical data to provide a range of estimates for spill probability. However, there is one major deficiency related to the reliability criterion:

1. ***Incomplete inventory of confidence intervals for spill rates calculated based on historical spill data***

   Anderson et al. (2012) and Anderson and LaBelle (2000) do not provide a comprehensive inventory of confidence intervals for spill rates for use in the OSRA model. The most recent spill rate data updated by Anderson et al. (2012) express spill rates as the mean number of spills per Bbbl and omit confidence levels for tanker spills at port and at sea. Although an earlier study from Anderson and LaBelle (2000) calculates confidence intervals for tanker spill rates for spills ≥1,000 bbl, the authors do not determine confidence intervals for any tanker spills ≥10,000 bbl, including spills in international waters and spills from the transportation of Alaska North Slope crude oil. Furthermore, Anderson and LaBelle (2000) do not provide confidence intervals for pipeline spill rates calculated based on historical data for the Trans-Alaska Pipeline System and crude oil/condensate spills associated with onshore Alaska North Slope crude oil production.

*Evaluation: There is one major deficiency related to the clarity criterion and thus this criterion is **partially met**.*

Validity

Criterion: Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis.

The OSRA model was developed in 1975 by the United States Department of the Interior (Smith et al. 1982) and the methodology has undergone independent peer-review on numerous occasions since its development. In addition to the recent study from Anderson et al. (2012) estimating oil spill occurrence, spill rate assumptions for the OSRA model have been independently peer-reviewed on four separate occasions (BOEM undated): three previous studies by Anderson and LaBelle (1990; 1994; 2000) examine occurrence rates used in the analysis of accidental oil spills on the US Outer Continental Shelf and a study by Lanfear and Amstutz (1983) examines cumulative frequency distributions of oil spills and determined that volume of oil handled is the most practical exposure variable for estimating oil spill probabilities. We acknowledge that, although BOEM (undated) refers to "independently peer-reviewed papers", authors that undertook the reviews (Anderson, LaBelle, Lanfear, and Amstutz) are identified with the BOEM (Minerals Management Service) of the US Department of the Interior. However, the reviews were published in journals and were subject to a blind peer review process prior to publication.

To ensure the validity of our application of the OSRA model to the ENGP, we submitted the findings of this report to Robert P. LaBelle, Science Advisor with BOEM in the US Department of the Interior. Mr. LaBelle is an expert in offshore energy exploration and development and has been working with the OSRA model as early as 1985. Prior to being Science Advisor, Mr. LaBelle was the acting Deputy Director for Bureau of Safety and Environmental Enforcement and was the Associate Director for Offshore Energy at the Bureau of Ocean Energy Management, Regulation and Enforcement. Mr. LaBelle independently verified our application of the OSRA model to the ENGP and validated our results.

*Evaluation: There are no major deficiencies related to the validity criterion and thus this criterion is **fully met**.*

Risk Acceptability

Criterion: Stakeholders identify and agree on acceptable levels of risk in a participatory, open decision-making process and assess risk relative to alternative means of meeting project objectives.

Determining levels of risk acceptability is an exercise that must take place in the context of a larger planning process. Any discussion of risk acceptability depends on the planning or regulatory review process and the stakeholders actively involved in that process. We avoid any speculation on how the OSRA model would affect a discussion around risk acceptability in the ENGP regulatory review process. We also avoid any comparison of historical cases where the OSRA may have been an input to a decision-making process where risk acceptability is discussed, since the outcome provides little insight on risk acceptability in the ENGP regulatory review process. Thus, we cannot determine risk acceptability in the absence of a participatory planning process in which tolerable levels of risk are discussed among stakeholders.

*Evaluation: The criterion for risk acceptability is **not applicable**.*

6.6. Summary of Findings for Qualitative Assessment of OSRA Model

Our evaluation of the OSRA model with best practices for risk assessment determined that the methodology incorporates several of the best practices (Table 46). Four of the seven best practice criteria for risk assessment have no major deficiencies and thus are fully met. Our analysis reveals a total of two major deficiencies in the application of the OSRA model to estimate spill probabilities for ENGP tanker and pipeline spills and thus the two criteria of reasonableness and reliability were only partially met. The criterion for risk acceptability is not applicable since defining risk acceptability must occur in the context of a planning or project review process.

Table 46: Results for the Evaluation of the OSRA Model with Best Practices for Risk Assessment

Criterion	Major Deficiencies	Result
Transparency *Documentation fully and effectively discloses supporting evidence, assumptions, data gaps and limitations, as well as uncertainty in data and assumptions, and their resulting potential implications to risk*	No major deficiencies	**Fully Met**
Replicability *Documentation provides sufficient information to allow individuals other than those who did the original analysis to obtain similar results*	No major deficiencies	**Fully Met**
Clarity *Risk estimates are easy to understand and effectively communicate the nature and magnitude of the risk in a manner that is complete, informative, and useful in decision making*	No major deficiencies	**Fully Met**
Reasonableness *The analytical approach ensures quality, integrity, and objectivity, and meets high scientific standards in terms of analytical methods, data, assumptions, logic, and judgment*	1. Historical spill data may not represent similar operating conditions as ENGP tanker and pipeline operations	**Partially Met**
Reliability *Appropriate analytical methods explicitly describe and evaluate sources of uncertainty and variability that affect risk, and estimate the magnitudes of uncertainties and their effects on estimates of risk*	2. Incomplete inventory of confidence intervals for spill rates calculated based on historical spill data	**Partially Met**
Validity *Independent third-party experts review and validate findings of the risk analysis to ensure credibility, quality, and integrity of the analysis*	No major deficiencies	**Fully Met**
Risk Acceptability *Stakeholders identify and agree on acceptable levels of risk in a participatory, open decision-making process and assess risk relative to alternative means of meeting project objectives*	Risk acceptability cannot be determined in the absence of a participatory planning process in which levels of risk are discussed among stakeholders	**N/A**

Note: n/a = not applicable.

7. Comparison of Spill Estimates for the ENGP

The following section compares spill forecast methodologies from the ENGP regulatory application with the OSRA Model. We compare both methods by describing the methodologies and spill estimates of each approach, as well as summarizing the results of our qualitative assessment. We then discuss the implications of the results of our analysis on the likelihood criterion required under the *CEAA*.

There are major differences between the methods estimating spill likelihood in the ENGP regulatory application and the OSRA model (Table 47). First, ENGP risk analyses estimate spill likelihood based on the number of spills per distance travelled by tankers, spills per tanker operation at the marine terminal, and spills per km of pipeline, whereas the OSRA model uses a different methodology based on the volume of hydrocarbons transported. Thus for tanker spills, DNV estimates spill likelihood for only the BC portion of the tanker trip while the OSRA estimates spill likelihood for the entire trip. Second, ENGP risk analyses use different datasets than the OSRA model for tanker and pipeline spills and these different datasets represent different spill size categories. Any comparison between spill likelihood estimates from the ENGP regulatory application and estimates from the OSRA model should consider the disparate spill size categories unique to each methodology. Third, the different methodologies require different data inputs in order to estimate spill probabilities. The methodology for estimating tanker spill likelihood in the ENGP application uses six major data inputs, whereas the OSRA model is a much simpler methodology that relies on two straightforward inputs. Fourth, both methodologies produce different outputs that communicate very different conceptions of spill risk. The ENGP regulatory application presents return periods for tanker, terminal, and pipeline spills that represent the amount of time between spill events, whereas the OSRA model presents the probability of a spill occurring over the operational life of the project, which in the case of the ENGP is 30 to 50 years.

Table 47: Comparison of Methodologies Estimating Spill Likelihood in ENGP Risk Analyses and the OSRA Model

	ENGP Risk Analyses	OSRA Model
Method	• Tanker: Spills per voyage • Terminal: Spills per tanker operation • Pipeline: Spills per kilometer of pipe	• Spills per volume of hydrocarbon transported
Source Data	• Tanker and Terminal: LRFP data; DNV data • Pipeline: NEB data; Data from recently constructed pipelines, US PHMSA Data	• Tanker (in port and at sea): BSEE database • Pipeline: State of Alaska data
Spill Size Categories	• Tanker o Any size spill o Oil spills > 5,000 m^3 (> 31,500 bbl) o Oil spills > 20,000 m^3 (> 125,800 bbl) o Oil spills > 40,000 m^3 (> 251,600 bbl) • Terminal o Spills < 1,000 m^3 (< 6,300 bbl)* • Pipeline o Leaks and Ruptures^	• Tanker o ≥ 1,000 bbl (≥ 159 m^3) o ≥ 10,000 bbl (≥ 1,590 m^3) o ≥ 100,000 bbl (≥ 15,900 m^3) • Pipeline o ≥ 500 bbl (≥ 80 m^3)
Major Data Inputs	• Tanker/Terminal: o Incident frequencies o Local scaling factors o Conditional probabilities o Route distance o Tanker distribution o Mitigation measures • Pipeline: o Spill frequencies o Length of the pipeline o Improvement factors	• Spill rates • Volume of hydrocarbon handled
Risk Outputs	• Unmitigated and mitigated return periods	• Probabilities over the life of the project

* DNV refers to small (< 10 m^3) and medium (10 m^3 to 1,000 m^3) terminal spills as 'any size spill' even though larger spills (> 1,000 m^3) are not included.
^ Average size oil or condensate pipeline leak is 94 m^3, average size oil pipeline rupture is 2,238 m^3 and average size condensate rupture is 823 m^3 (WorleyParsons 2012).

Table 48 includes a summary of spill estimates for tanker, terminal, and pipeline spills developed from the various methodologies for the ENGP at its planned throughput capacity. Based on spill estimates from ENGP risk analyses, a tanker, terminal, or pipeline spill could occur every 2 years[30]. Since return periods in the ENGP application estimate the amount of time between spills and not the chance of a spill over the life of the project, we restate return periods as probabilities over the life of the ENGP[31]. The results show that a tanker, terminal, or pipeline spill has a 99.9% chance of occurring during 30 years of

[30] Return period calculated based on the following ENGP spill probabilities: (1) any size tanker spill; (2) any size terminal spill, and; (3) pipeline leaks.
[31] To restate spill likelihood, we convert return periods to annual spill probabilities and estimate spill probabilities over the life of the project. We make no other adjustments to any of the data inputs in DNV's methodology; our analysis simply restates return periods as probabilities over the life of the ENGP. Furthermore, we do not adjust for any deficiencies identified in the qualitative assessment that would likely result in further increases in spill probability.

operation. Our application of the OSRA model also estimates high spill probabilities for ENGP tanker and pipeline operations. Based on the results of the OSRA modelling, the minimum probability for a tanker or pipeline spill over a 30-year operating period is 96.8% and this increases to 99.7% over 50 years. When we restate spill probabilities from the OSRA model as return periods, a spill from ENGP tanker or pipeline operations could occur every 3 to 9 years[32]. Note that any comparison of the overall return periods and spill probabilities for ENGP risk analyses and the OSRA model in Table 48 must consider the different spill size categories for each method.

Table 48: Comparison of Return Periods and Spill Probabilities for the ENGP

Method	Size and Type of Spill		Return Period (in years)	Spill Probability (%)	
				30 years	**50 years**
ENGP Risk Analyses#	Tanker any size spill	Oil	110 - 350	8.2 - 24.0	13.3 - 36.7
		Oil/Condensate	78 - 250	11.3 - 32.1	18.2 - 47.5
	Tanker spill ≥ 31,500 bbl	Oil	200 - 550	5.3 - 14.0	8.7 - 22.2
	Terminal any size spill	Oil	34 - 90	28.5 - 59.2	42.8 - 77.5
		Oil/Condensate	29 - 62	38.6 - 65.1	55.6 - 82.7
	Pipeline leak (594 bbl)	Oil	4	99.9	99.9
		Oil/Condensate	2	99.9	99.9
	ENGP Spill*	Oil/Condensate	**2**	**99.9**	**99.9**
OSRA Model	Tanker spill ≥ 1,000 bbl	Oil	7 - 17	84.1 - 99.2	95.3 - 99.9
		Oil/Condensate	5 - 12	91.9 - 99.9	98.5 - 99.9
	Tanker spill ≥ 10,000 bbl	Oil	13 - 48	46.9 - 91.1	65.1 - 98.2
		Oil/Condensate	10 - 35	57.9 - 96.3	76.3 - 99.6
	Tanker spill ≥ 100,000 bbl	Oil	31 - 174	15.8 - 62.4	25.0 - 80.4
		Oil/Condensate	23 - 128	21.0 - 73.7	32.5 - 89.2
	Pipeline Spill ≥ 500 bbl	Oil/Condensate	8 - 32	61.1 - 97.7	79.2 - 99.8
	ENGP Spill**	Oil/Condensate	**3 - 9**	**96.8 - 99.9**	**99.7 - 99.9**

Source: Brandsæter and Hoffman (2010); Calculations based on Anderson et al. (2012); WorleyParsons (2012).
Note: Data for both methodologies represent planned throughput capacity of 525 kbpd of oil and 193 kbpd of condensate;
* Overall spill probability for ENGP based on spill probabilities for any size tanker spill, any size terminal spill, and pipeline leaks.
** Calculation based on spill probabilities for tanker spills ≥ 1,000 bbl and pipeline spills ≥ 500 bbl.
# Range represents unmitigated and mitigated spill data with the exception of pipeline spills.

To address challenges of comparing spill estimates from the fundamentally different methodologies used in the ENGP regulatory application and OSRA model, we developed an evaluative framework of best practice criteria for risk assessment to evaluate each approach. Our analysis examines how each methodological approach satisfies best practice criteria and identifies major deficiencies of both methodologies. As shown in Table 49, our analysis identifies a total of 28 major deficiencies in the methodological approach used in the ENGP application to estimate spills from ENGP operations. As a result, all seven criteria are not met. The OSRA model has only two major deficiencies and fully meets four of the seven best practice criteria.

[32] To estimate return periods for the entire ENGP with the OSRA model, we take the inverse of the following annual spill probabilities: (1) oil/condensate tanker spills ≥ 1,000 bbl and; (2) oil/condensate pipeline spills ≥ 500 bbl.

Table 49: Summary and Comparison of Results for the Qualitative Assessment

Best Practice Criterion for Risk Assessment	ENGP Application		OSRA Model	
	Major Deficiencies	Qualitative Assessment	Major Deficiencies	Qualitative Assessment
Transparency	6	Not Met	0	Fully Met
Replicability	5	Not Met	0	Fully Met
Clarity	5	Not Met	0	Fully Met
Reasonableness	5	Not Met	1	Partially Met
Reliability	2	Not Met	1	Partially Met
Validity	2	Not Met	0	Fully Met
Risk Acceptability	3	Not Met	n/a	n/a
Total	**28**	**-**	**2**	**-**

N/A = not applicable.

Results of our qualitative assessment provide insight on the relative strengths and weaknesses of the methodologies used in the ENGP application and the OSRA model. Methodologies estimating spill risk in the ENGP application contain major deficiencies that include a lack of transparency for several key data inputs that reduce spill likelihood, a failure to communicate risk as the probability of a spill over the life of the project, no consideration of risks from the project that might occur outside the study area, a lack of expert review of main findings, and a failure to define acceptable levels of risk in terms of stakeholder values. Based on these deficiencies, methodologies estimating spill likelihood in the ENGP application fail to address the *CEAA* decision criterion.

Our qualitative assessment of the OSRA model suggests that the OSRA model meets more of the best practices criteria than the ENGP application, which is partly attributable to the parsimonious approach of the OSRA model. Our application of the OSRA model to the ENGP has only two major deficiencies and fully meets four of the best practices for risk assessment methodologies. The OSRA model presents spills as probability of occurrence over the 30- and 50-year life of the project and thus satisfies the *CEAA* decision criterion for the likelihood of significant adverse environmental effects. Indeed, the OSRA model demonstrates that there is a high likelihood that the ENGP will cause significant adverse environmental effects. The OSRA model also considers tanker spills outside Canada since the methodology for estimating tanker spill probabilities uses a per-volume approach rather than the distance-based method used by DNV that only examines tanker spills within the territorial waters of Canada.

In summary, both methods have strengths and weaknesses and without further analysis we are unable to confirm which method provides a more accurate estimate of the likelihood of spills for the ENGP. However, based on our analysis the OSRA model satisfies *CEAA* decision criteria whereas ENGP risk analyses fail to provide decision makers with the necessary information required to accurately assess the likelihood of significant adverse environmental effects from a spill. Notwithstanding the differences in methodologies, both the OSRA model and ENGP risk analyses determine that a spill from the ENGP is likely to occur.

8. Conclusion

This report evaluates spill estimates for ENGP tanker, terminal, and pipeline operations. We evaluate spill estimates in the ENGP regulatory application, apply the OSRA model to estimate spill probabilities for the ENGP, and compare the results of both approaches using a qualitative assessment based on best practices for risk assessment. From our analysis we conclude:

1. The ENGP Application Contains Major Deficiencies that Underestimate Spill Likelihood

Enbridge's spill risk analysis contains 28 major deficiencies. As a result of these deficiencies, Enbridge underestimates the risk of the ENGP. Some of the key deficiencies include:

- Failure to present the probabilities of spills over the operating life of the ENGP
- Failure to evaluate spill risks outside the narrowly defined BC study area
- Reliance on LRFP data that underreport tanker incidents by between 38 and 96%
- Failure to include the expansion capacity shipment volumes in the analysis
- Failure to provide confidence ranges of the estimates
- Failure to provide adequate sensitivity analysis
- Failure to justify the impact of proposed mitigation measures on spill likelihood
- Potential double counting of mitigation measures
- Failure to provide an overall estimate of spill likelihood for the entire ENGP
- Failure to disclose information and data supporting key assumptions that were used to reduce spill risk estimates
- Failure to use other well accepted risk models such as the US OSRA model.

2. Deficiencies in the ENGP Application Fail to Address the *CEAA* Decision Criterion

Due to deficiencies in the oil spill risk assessment, Enbridge does not provide an accurate assessment of the likelihood of significant adverse environmental impacts as required under *CEAA*. Enbridge expresses the likelihood of a spill as return periods for separate components of the project (tanker, terminal, and pipeline) rather than the probability of a spill over the life of the project. Without estimates of the probability of a spill over the operating life of the project, decision makers are unable to determine whether the project meets the *CEAA* criterion of likelihood of adverse environmental effects. Furthermore, due to the deficiencies in the spill risk methodology, Enbridge fails to adequately disclose the extent of risk associated with the ENGP and the uncertainty in estimating risk.

3. Restating Enbridge's Own Findings as Probabilities Over Project Life Shows that Spill Likelihood is High

When findings in the ENGP application are restated as the probability of a spill over the operational life of the ENGP instead of return periods, the conclusion based on Enbridge's own analysis is that the likelihood of a spill is high (Table 50). These spill probabilities based on Enbridge's analysis underestimate spill likelihood because they are based on methodological deficiencies.

Table 50: Probabilities for ENGP Tanker, Terminal, and Pipeline Spills (50 Years)

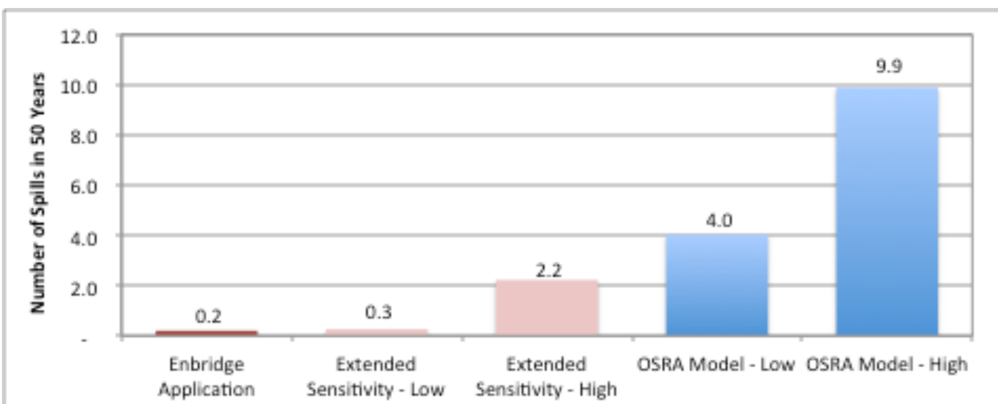
Spill Type (Oil or Condensate)	**Spill Probability over 50 years** (%)
Tanker Spill	18.2
Terminal Spill	55.6
Pipeline Spill	99.9
Combined Spills	99.9

4. Sensitivity Analysis Shows that the Likelihood of a Spill is High

Our extended sensitivity analysis for the ENGP demonstrates that there is a higher likelihood of spill occurrence than reported in the ENGP application. For tanker spills, the extended sensitivity analysis evaluates changes to key input parameters such as increasing shipments to the ENGP design capacity and combining parameter changes.

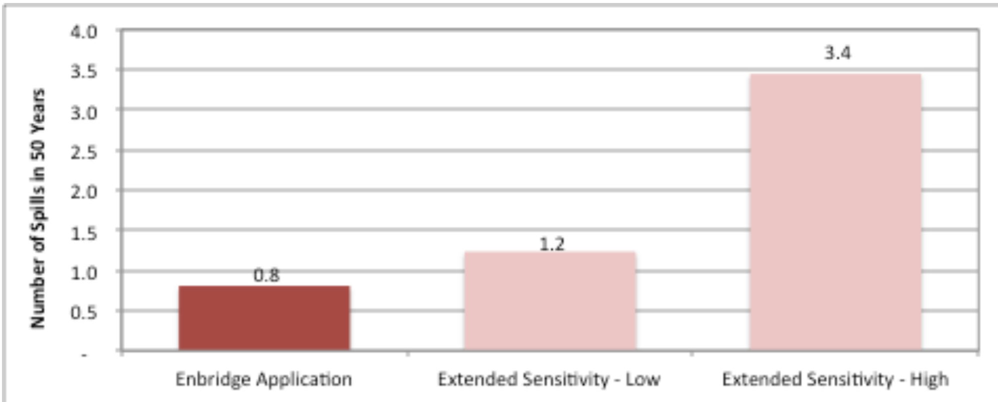
a. The extended sensitivity analysis shows that based on Enbridge's own data, the rate of tanker spills could range between 0.3 and 2.2 spills over a 50-year period, much higher than Enbridge's estimate of less than one spill (Figure 4). This range still understates spill risk because it does not correct for all the deficiencies in Enbridge's methodology.

Figure 4: Number of ENGP Tanker Spills in 50 Years (Oil and Condensate)



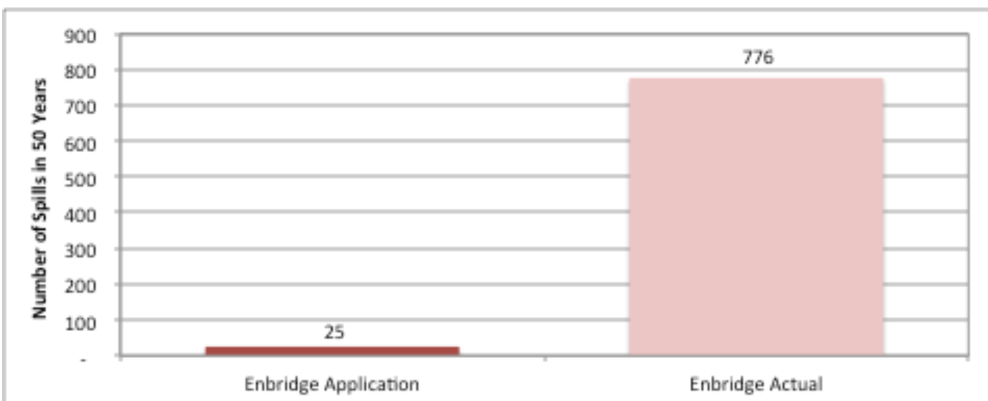
b. The extended sensitivity analysis for terminal spills determines that the rate of spills in a 50-year period could range between 1.2 and 3.4 spills for any size terminal spill, significantly higher than Enbridge's estimate of less than one spill in 50 years (Figure 5).

Figure 5: Number of ENGP Terminal Spills in 50 Years (Oil and Condensate)



c. The extended sensitivity analysis using spill frequency data from Enbridge's liquid pipeline system results in an estimated 776 oil and condensate pipeline spills in 50 years (or between 15 to 16 spills per year), which is 31 times more frequent than Enbridge's estimate of 25 spills in 50 years (Figure 6).

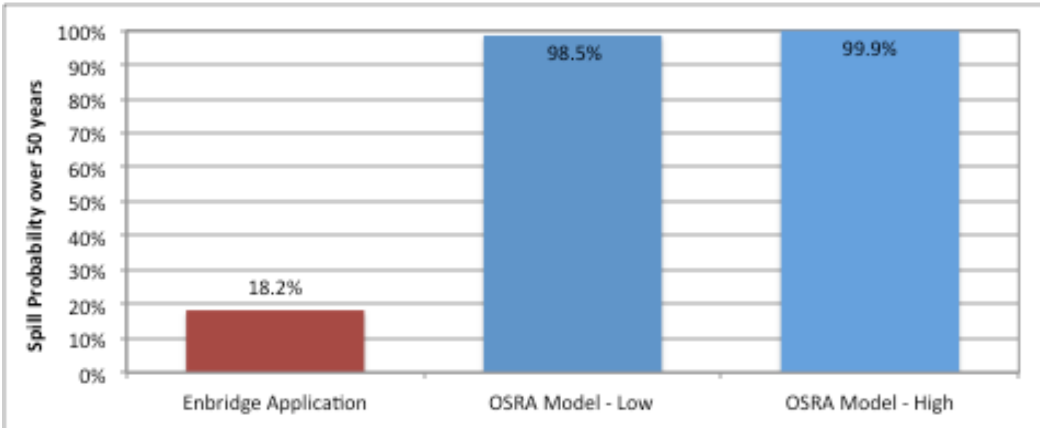
Figure 6: Number of ENGP Pipeline Spills in 50 Years (Oil and Condensate)



5. The OSRA Model Shows the Probability of a Major Spill is High

The OSRA model is the model the US government uses to estimate spill risk. The OSRA model estimates 4 to 10 tanker spills over 1,000 bbl (159 m^3) could occur in a 50-year period (Figure 4), which is 20 to 50 times more frequent than Enbridge's estimate. Due to mitigation measures, the lower end of the OSRA spill range is more likely a better indicator of future risk. In terms of spill probability, the OSRA model estimates that an oil/condensate tanker spill ≥ 1,000 bbl has a 98.5% to 99.9% chance of occurring over a 50-year operating period, well above Enbridge's estimate of 18.2% (Figure 7). The lower estimate of 98.5% is likely a better indication of future spill risk due to mitigation measures. The probability of a tanker spill increases to 99.9% if the volume of oil and condensate handled increases to the ENGP expansion capacity of 1,125 kbpd.

Figure 7: Probabilities for ENGP Tanker Spills over 50 years (Oil or Condensate)



6. Other Considerations

Finally, two important considerations must be reconciled in the ENGP regulatory application: risk acceptability to stakeholders, and viable alternatives to the ENGP that reduce risk. Risk acceptability in the ENGP application relies on a technical definition of risk. Acceptable risk however is a value judgment that should be based on the definition of risk as defined by impacted stakeholders. Stakeholders' definition of acceptable risk therefore needs to be assessed and used in the ENGP decision. Second, Enbridge has not identified nor compared viable alternatives that meet the stated purpose of the ENGP. There are viable alternatives to shipping crude oil from the Western Canada Sedimentary Basin to market that involve no risk from oil tanker spills (Gunton and Broadbent 2012a) and thus risk from tanker spills can be eliminated. These alternatives should be evaluated relative to the ENGP to assess the most cost effective transportation option.

7. Overall Conclusion

We acknowledge that estimating risk is challenging due to the many uncertainties involved and that different assumptions and methodologies will produce different assessments of risk. The key in risk assessment is to test a range of assumptions and methodological approaches to provide a clear and accurate assessment of the range of likely outcomes so that decision makers can fully judge risk. The conclusion of this report is that Enbridge's oil spill risk assessment contains methodological deficiencies and does not therefore provide an accurate assessment of the degree of risk associated with the ENGP. The risk assessment in this report also concludes that the ENGP has a very high likelihood of a spill that may have significant adverse environmental effects.

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Appendix A - Detailed Summary of ENGP Spill Risk Analysis

This appendix provides a detailed summary of the methodologies used by Enbridge and its consultants to estimate spill likelihood for ENGP tanker, terminal, and pipeline spills. This summary relies on the same regulatory documents referenced in section 3 in the main body of the report.

1. Spills from Tanker Traffic Accessing Kitimat Terminal

DNV determines spill return periods for tanker traffic accessing Kitimat Terminal in the *Marine Shipping Quantitative Risk Analysis* prepared for the Northern Gateway Project on behalf of Enbridge. DNV uses a per-voyage methodology to forecast spills in the marine shipping QRA based on nautical miles (nm) travelled by tankers within the study area. The methodology consists of the following steps:

- Determine base incident frequencies per nm
- Apply scaling factors to base incident frequencies to adjust for local conditions
- Determine conditional spill probabilities from an assessment of incident consequences
- Calculate unmitigated spill return periods based on scaled incident frequencies and conditional probabilities
- Conduct sensitivity analysis
- Identify mitigation measures and recalculate spill return periods based on mitigation

Base Incident Frequencies

As part of the per-voyage methodology, DNV determines base incident frequencies from historical tanker incident data and uses various assumptions to estimate incident frequencies per nm. DNV determines frequencies for international tanker incidents based on data from Lloyds Register Fairplay (LRFP) for the period 1990-2006 (Brandsæter and Hoffman 2010 p. 5-49). DNV examines four types of potential incidents associated with tanker traffic:

1. Powered and drift grounding, whereby a tanker runs aground either with functional mechanical and navigation equipment (powered) or as a result of failed propulsion equipment (drift)
2. Collisions, whereby the navigational failure of one or both vessels results in a collision
3. Foundering, whereby a tanker sinks due to structural failure of the hull from weather or structural defects
4. Fire and/or explosion.

As shown in Table A-1, DNV calculates LRFP incident frequencies per nm based on the following assumptions of the average distance travelled by a tanker per year for each tanker incident type:

- Tankers sail in coastal areas where a powered grounding may occur 10% of the time at sea (Rabaska 2004 as cited in Brandsæter and Hoffman 2010)
- Tankers sail in areas with heavy traffic where collisions may occur 20% of the time at sea (Rabaska 2004 as cited in Brandsæter and Hoffman 2010)
- Tankers sail in areas where land is within drifting distance and drift grounding may occur if the ship loses power 15% of the time at sea
- Tankers sail in open water where foundering may occur 90% of the time at sea.

DNV supports the first two assumptions with reference to a *TERMPOL Study* completed for Rabaska (2004), while the assumptions for drift grounding and foundering are not supported with evidence.

Table A-1: Base Incident Frequencies for Tanker Incidents based on Per-Voyage Methodology

	Powered Grounding	Drift Grounding	Collision	Foundering	Fire/ Explosion
Base LRFP incident frequency (per ship year*)	4.42E-03	1.11E-03	6.72E-03	3.36E-05	2.41E-03
Average distance sailed by tanker (nm)	74,022				
Portion of total distance sailed by where incident may occur	10%	15%	20%	90%	100%
Distance sailed by tanker where incident may occur	7,402	11,103	14,804	66,620	74,022
Base LRFP incident frequency (per nm)	5.98E-07	9.96E-08	4.54E-07	5.04E-10	3.26E-08

Source: Brandsæter and Hoffman (2010 p. 5-51).
* One ship year represents a total sailing distance of 74,022 nm per year per tanker in operation.

Local Scaling Factors

DNV then calculates incident data for the BC study area by multiplying the international frequency data from LRFP by scaling factors that compare risks in the study area to the international areas on which the incident data are based. DNV identified scaling factors from a qualitative assessment of the international data and the scaling factors underwent a review by experts familiar with marine risk assessment, tanker operations, and global navigation (Brandsæter and Hoffman 2010 p. 5-52). DNV uses the following formula to calculate incident frequencies for the BC study area where $Frequency_{BC\text{-}Coast}$ is the scaled incident frequency per nm, F_{base} is the base incident frequency per nm from LRFP in Table A-1, and $K_{local\text{-}scaling\text{-}factor}$ is the total of local scaling factors identified in Table A-2:

$$Frequency_{BC-Coast} = F_{base} * K_{local-scaling-factor}$$

DNV divides the BC study area into nine segments and assesses scaling factors for each incident type. The comparison uses 1.0 as a baseline and thus a scaling factor equal to 1.0 suggests that the local conditions affecting risk are equal to the world average (Brandsæter and Hoffman 2010 p. 5-52). Risk factors assessed by DNV depend on the type of incident and include the following categories:

- *Navigational route*: number of course changes
- *Measures*: use of pilots with local knowledge
- *Navigational difficulty*: visibility, currents, and disturbance from other vessels
- *Distance to shore*: distance from ship to shore
- *Emergency anchoring*: possibility to drop an emergency anchor
- *Traffic density*: Number of vessels encountered during transit
- *Weather conditions*: Accounts for winds and currents.

Table A-2 summarizes scaling factors used by DNV for each incident type. DNV applied three scaling factor categories to assess powered groundings and collisions, two scaling factors to assess drift groundings, and one factor (weather) to assess foundering incidents. Scaling factors range from 0.001 to 1.94 for all incident types. The overall average scaling factor for each incident type ranges between 0.22 for collision incidents and 1.11 for drift grounding incidents, with the exception of incidents involving fire or explosion, which DNV does not scale to represent local conditions. DNV does not provide any information on the routes that the ENGP routes are being compared to so it is not possible to assess the basis or accuracy of the scaling factors.

Table A-2: Local Scaling Factors for Tanker Incident Frequencies

Incident Type	Scaling Factor Category			Range of Total Scaling Factors	Average Scaling Factor*
Powered Grounding	Navigational Route	Measures	Navigational Difficulty	0.001 – 1.94	0.91
Drift Grounding	Distance to Shore	Emergency Anchoring	-	0.01 – 1.56	1.11
Collision	Traffic Density	Measures	Navigational Difficulty	0.01 – 0.54	0.22
Foundering	Weather Conditions	-	-	0.01 – 1.50	0.80
Fire/ Explosion	n/a				

Source: Brandsæter and Hoffman (2010).
* Calculated based on data from Brandsæter and Hoffman (2010).

Conditional Probabilities

After estimating the frequency of a tanker incident occurring by multiplying scaling factors times the international incident frequency rate, DNV determines the probability of a spill resulting from a tanker incident. DNV uses two different methods to estimate conditional spill probabilities.

Method 1

The first method (Method 1) determines conditional spill probabilities based on LFRP data. According to Brandsæter and Hoffman (2010), LRFP categorize damages for the four incident types based on the following categories:

- *Minor Damage*: Damages cause small indents to the vessel but do not penetrate the outer hull; there is very minor damage involving little repair

- *Major Damage*: Damage to the tanker penetrates the outer hull but the spill event is not categorized as total loss; structural, mechanical, or electrical damage that require repairs; a breakdown results in the tanker being towed
- *Total Loss*: The tanker ceases to exist after an accident; cost of repairs exceeds insured value of ship; all cargo is lost.

LRFP data provides a frequency distribution for each damage category identified above depending on the incident type (Table A-3). For example, the frequency distribution of damages for a grounding incident suggests that 57.2% of incidents result in minor damage, 40.4% result in major damage, and only 2.4% of incidents result in total loss of the tanker (Brandsæter and Hoffman 2010 p. 6-79).

DNV determines conditional spill probabilities for each incident type and damage category. According to DNV, "The conditional probability of a spill has been estimated by DNV based on the research of spill to damage data" (Brandsæter and Hoffman 2010 6-79). DNV then multiplies frequency distributions by probabilities of a spill for laden tankers and tankers in ballast for each damage category to determine the total conditional spill probabilities for each incident type. DNV disaggregates conditional probabilities presented in Table A-3 by laden tankers carrying oil or condensate and tankers in ballast carrying bunker fuel. For example, the conditional spill probability for a laden tanker running aground is (57.2% x 0%) + (40.4% x 75%) + (2.4% x 100%) = 32.7% and thus a spill is predicted 32.7% of the time a grounding incident occurs that involves a laden tanker.

Table A-3: Damage Frequencies and Conditional Probabilities for Tanker Incidents (Method 1)

Incident Type	Damage Category	LRFP Frequency Distribution (%)	Conditional Probability of Spill (%)	
			Laden	**Ballast**
Grounding	Minor	57.2	0	0
	Major	40.4	75	10
	Total Loss	2.4	100	100
	Total Conditional Probability		**32.7**	**6.4**
Collision	Minor	74.5	0	0
	Major	25.5	75	10
	Total Loss	Negligible	100	100
	Total Conditional Probability		**19.1**	**2.6**
Foundering	Minor	0	-	-
	Major	0	-	-
	Total Loss	100	100	100
	Total Conditional Probability		**100**	**100**
Fire/ Explosion	Minor	48.8	0	0
	Major	48.4	50	10
	Total Loss	2.8	100	100
	Total Conditional Probability		**27.0**	**7.6**

Source: Brandsæter and Hoffman (2010 p. 6-79; 6-83; 6-87; 6-88).

Method 2

The second method (Method 2) estimates spill quantities for bottom and side damages based on information from the International Marine Organization International

Convention for the Prevention of Pollution from Ships (MARPOL) and estimates spill size distribution with Naval Architecture Package software. Furthermore, Method 2 uses Monte Carlo simulation to estimate probabilities for various spill sizes for groundings and collisions.

Table A-4 presents results for probabilities and spill volumes calculated with Method 2. According to DNV calculations, if the largest laden tanker ($VLCC_{max}$) forecast to call at Kitimat Terminal ran aground, there is an 18.7% probability that the damaged vessel would spill oil. DNV also estimates that the average amount of oil released from a $VLCC_{max}$ spill due to grounding is 1,725 m^3, while an extreme outflow - defined as the mean of the highest outflow decile - is 15,506 m^3 (Brandsæter and Hoffman 2010 p. 6-80).

Table A-4: Conditional Spill Probabilities and Spill Volumes for Grounding and Collision Incidents (Method 2)

Tanker Type		Grounding			Collision		
		Conditional Spill Probability (%)	**Mean Oil Outflow** (m^3)	**Extreme Oil Outflow** (m^3)	**Conditional Spill Probability** (%)	**Mean Oil Outflow** (m^3)	**Extreme Oil Outflow** (m^3)
Laden Vessel	$VLCC_{max}$	18.7	1,725	15,506	23.9	1,399	35,839
	VLCC	18.7	1,616	14,469	24.9	1,397	35,605
	Suezmax	17.5	1,106	9,481	27.7	1,280	28,980
	Aframax	18.0	736	6,710	21.0	638	17,539
Vessel in Ballast	VLCC	0.2	1.01	11	8.3	210	2,101
	Suezmax	< 0.1	0.01	0.11	5.7	86	860
	Aframax	< 0.1	0.08	0.7	14.2	174	1,414

Source: Brandsæter and Hoffman (2010 p. 6-80; 6-84).
Note: Extreme oil outflow represents the mean of the 10% of bottom damage incident with the most outflow.

For grounding and collision incidents, Method 1 and Method 2 estimate two sets of conditional probabilities. Spill probabilities of 17.5% to 18.7% for laden tankers running aground compare with the conditional probability of 32.7% for the same incident type determined in Method 1 using LRFP data. DNV states that, due to the rocky local seabed conditions, the higher conditional probability of 32.7% is used in subsequent chapters to determine unmitigated and mitigated spill probabilities (Brandsæter and Hoffman 2010 p. 6-81). Similarly, the probability of a spill from a collision for a laden tanker in Method 1 is 19.1% and conditional probabilities for laden vessels calculated using Method 2 range between 21.0% and 27.7%. DNV uses the lower probability of 19.1% claiming that, compared to the world average, the probability of a tanker being struck at a perpendicular angle in the cargo or fuel tank area of the vessel is lower due to the local traffic pattern (Brandsæter and Hoffman 2010 p. 6-84).

In addition to determining spill probabilities for various tanker sizes and mean and extreme oil outflows, Method 2 also estimates probabilities for grounding and collision spills exceeding a certain volume. According to the Monte Carlo simulation, the probability of a spill greater than 10,000 m^3 for a laden VLCC grounding is 5.5% and

25% for a collision (Brandsæter and Hoffman 2010 p. 6-81 - 6-85). The probability of a grounding spill exceeding 25,000 m^3 and 40,000 m^3 is 1% and 0.2%, respectively, while the probability of a collision spill exceeding 20,000 m^3 and 50,000 m^3 is 10% and 0.3%, respectively (Brandsæter and Hoffman 2010 p. 6-81 - 6-85).

Unmitigated Spill Return Periods

DNV estimates unmitigated spill return periods for each type of tanker incident based on scaled incident frequencies, conditional probabilities, the length of each segment, and the number of times the route is travelled per year. DNV presents unmitigated risk as a return period, which is the number of years between spill events, and is an alternative to stating the annual probability of a spill. The following equation represents the return period of a spill for a particular segment ($ReturnPeriod_{segment\ i}$) where $F_{i,j}$ is the frequency of incident type j in segment i, $d_{i,j}$ is the conditional probability of a spill given incident type j in segment i, X_i is the sailing distance in nm through segment i, and n is the annual number of times the route through segment i is travelled:

$$ReturnPeriod_{segment\,i} = 1/[\Sigma(F_{i,j} * d_{i,j}) * X_i * n]$$

DNV calculates return periods for unmitigated spills based on forecast traffic of 149 oil tankers and 71 condensate tankers and the distribution of tanker traffic on the northern and southern routes identified by Enbridge (see Table A-5). According to DNV, vessels will have the option of selecting which shipping route to access Kitimat Terminal and will select the route based on weather conditions and their final destination (Brandsæter and Hoffman 2010 p. 3-10). However, DNV allocates the majority of traffic (118 of 220 tankers or 54%) in its analysis to Caamano Sound, which has the shortest route distance of 190 nm and hence a lower return period than longer routes.

Table A-5: Distribution of Tanker Traffic Per Year

Route and Distance (nm)	**Oil**	**Condensate**	**Total**
North Route (251 nm)	73	0	**73**
South Route via Caamano Sound (190 nm)	61	57	**118**
South Route via Browning Entrance (259 nm)	15	14	**29**
Total	**149**	**71**	**220**

Source: Brandsæter and Hoffman (2010 p. 3-12; p. 7-105).

Table A-6 presents unmitigated spill return periods for each type of tanker incident. According to DNV, an unmitigated tanker incident will result in an oil/condensate spill once every 78 years and the return period for an unmitigated oil spill is 110 years.

Table A-6: Unmitigated Return Periods for an Incident Resulting in a Spill

Incident Type	Total Return Period (in years)	
	Oil/Condensate Spill	Oil Spill
Powered Grounding*	107	154
Drift Grounding*	535	742
Collision*	1,084	1,546
Foundering*	25,821	37,963
Fire/ Explosion*	1,838	2,623
Total	**78**	**110**

Source: Brandsæter and Hoffman (2010).
* Calculated from Brandsæter and Hoffman (2010).
Note: Total return period represents forecast traffic on all three routes.

DNV also estimates unmitigated return periods for various oil spill sizes. Based on oil spill size calculations for grounding and collisions estimated in Method 2 of the consequence assessment, DNV expects that over 41% of spills will exceed 5,000 m^3, while nearly 5% and 1% of spills will exceed 20,000 m^3 and 40,000 m^3, respectively (Table A-7). DNV determines that the unmitigated return period for oil spills greater than 5,000 m^3 is 200 years, while return periods for oil spills greater than 20,000 m^3 and 40,000 m^3 are 1,750 years and 12,000 years, respectively. DNV does not provide any rationale for the spill volume categories it uses to estimate these return periods and does not provide estimates for return periods for specific spill volume categories less than 5,000 m^3, even though spills as small as 238 m^3 can have significant adverse environmental impacts (US DOI 2003a).

Table A-7: Unmitigated Oil Spill Size Distributions and Return Periods

Spill Volume (m^3)	Unmitigated Distribution (%)	Estimated Return Period (in years)
> 5,000	41.5	200
> 20,000	4.5	1,750
> 40,000	0.8	12,000

Source: Calculated from Brandsæter and Hoffman (2010 p. 7-110).
Note: Estimates for unmitigated distribution of spill sizes should be considered as approximate estimates due to limited data provided by DNV.

Sensitivity Analysis for Unmitigated Spill Return Periods

DNV conducts a sensitivity analysis in its marine shipping QRA examining impacts of several parameters on spill probabilities. The four parameters include: (1) increased scaling factor for grounding, (2) increased traffic density, (3) increased/decreased number of tankers calling Kitimat Terminal, and (4) extending segments 5 and 8 to 200 nm. The sensitivity analysis tests the impact of changes in parameters on all three potential routes separately under the assumption that all 220 tankers forecast to call at Kitimat Terminal use the route being tested exclusively. Therefore, the spill probabilities do not account for using a combination of routes.

Sensitivity 1: Increased Scaling Factors for Grounding Incidents

The first parameter in the sensitivity analysis evaluates the effect of increasing scaling factors for powered and drift grounding by 20% for each of the nine route segments on the overall tanker spill return periods. DNV evaluates the sensitivity of this particular parameter because grounding is the most significant hazard that may occur on segments that have a high contribution to the overall risk per route (Brandsæter and Hoffman 2010 p 7-99). DNV provides no rationale for using the 20% increase in local scaling factors for grounding.

Table A-8 presents a comparison of the unmitigated return periods for baseline conditions and increased scaling factors for grounding for each tanker route. Return periods represent the 20% increase in scaling factors for grounding while leaving other scaling factors for other tanker incident types including collision, foundering, and fire and/or explosion unchanged. According to DNV calculations, increased scaling factors for powered and drift grounding incidents decrease return periods as much as 13 years for the South Route via Browning Entrance.

Table A-8: Sensitivity Analysis for a 20% Increase in Scaling Factors for Tanker Grounding Incidents

Sensitivity Parameter	North Route	South Route via Caamano Sound	South Route via Browning Entrance
Return Periods with Baseline Scaling Factors (in years)	69	83	84
Return Periods with 20% Increase in Scaling Factors for Grounding (in years)	59	71	71

Source: Brandsæter and Hoffman (2010 p. 7-100).
Note: Return periods represent all incident types for each route segment.

Sensitivity 2: Increased Traffic that Affects Collision Frequency

DNV examines the effect of increased traffic that affects collision frequency along the three routes on overall spill return periods. Scaling factors for traffic density for collision incidents increase between 0% and 50% for each route segment that, according to DNV, allows for the increase in forecast developments in Kitimat and the general increase in coastal vessel traffic (Brandsæter and Hoffman 2010 p. 7-100). Return periods for increased traffic densities for collision incidents also represent baseline scaling factors for powered and drift grounding, foundering, and fire and/or explosion. Based on the higher traffic density for collision incident frequencies, the overall return period for each tanker route decreases marginally by two years (Table A-9).

According to DNV, traffic density is "…relatively low, even with further projects taken into consideration" (Brandsæter and Hoffman (2010 p. 7-100). However, DNV does not provide a summary of future projects that it took into consideration and provides no evidence how it to relates modified scaling factors to potential increases in traffic at or near the Port of Kitimat referenced in the *TERMPOL Study 3.2: Origin, Destination, & Marine Traffic Volume Survey*. Despite increases, scaling factors for traffic density all remain well below the international average of 1.0. Furthermore, DNV does not clearly state whether the base case scaling factors that represent traffic density include planned tanker traffic associated with the ENGP.

Table A-9: Sensitivity Analysis for Increased Traffic Density for Tanker Collision Incidents

Sensitivity Parameter	North Route	South Route via Caamano Sound	South Route via Browning Entrance
Return Periods with Baseline Scaling Factors (in years)	69	83	84
Return Periods with Increased Traffic Density for Collisions (in years)	67	81	82

Source: Brandsæter and Hoffman (2010 p. 7-101).
Note: Return periods represent all incident types for each route segment.

Sensitivity 3: Increased/Decreased Number of Tankers

A sensitivity analysis examines the impact of a decrease in annual average tanker traffic from 220 vessels to 190 tankers and an increase to 250 tankers per year. DNV fails to provide a rationale for using this particular range for the number of vessels in its sensitivity analysis. It is important to note that the higher scenario of 250 tankers is still well below the planned expansion capacity to 1,125 kbpd that requires 331 tankers. As shown in Table A-10, increasing the number of sailings from 220 tankers to 250 reduces the return period by 8 to 10 years depending on the route (Brandsæter and Hoffman 2010 p. 7-102).

Table A-10: Sensitivity Analysis for Changes in the Number of Tankers Calling Kitimat Terminal

Sensitivity Parameter	North Route	South Route via Caamano Sound	South Route via Browning Entrance
190 Tankers	80	96	97
220 Tankers (Baseline)	69	83	84
250 Tankers	61	73	74

Source: Brandsæter and Hoffman (2010 p. 7-102).

Sensitivity 4: Route Extension to 200 Nautical Miles

DNV's final sensitivity analysis examines increases in the distance sailed by tankers in two segments of the northern and southern routes. DNV assumes that tankers navigating segment 5 and 8 travel a distance of 200 nm to reach the open Pacific Ocean as opposed to the baseline distance of 65 nm and 75 nm for each segment. DNV further assumes that incident frequencies and scaling factors for each incident type remain unchanged for the route extension to 200 nm in segments 5 and 8, even though DNV acknowledges that tankers travelling the extended route will navigate through areas with greater vessel traffic (Brandsæter and Hoffman 2010 p. 7-103).

Table A-11 compares spill return periods for an extension to 200 nm in segments 5 and 8 with baseline distances. An increase in segments 5 and 8 to 200 nm reduces the return period to 1,400 years and 1,500 years, respectively, for those particular segments. DNV does not calculate the effect of increased sailing distances in segment 5 and 8 on the overall unmitigated return period for each route.

Table A-11: Sensitivity Analysis for Route Extension on Segments 5 and 8

Sensitivity Parameter	Segment 5		Segment 8	
	Return Period (in years)		Return Period (in years)	
	Baseline 65 nm	Extension 200 nm	Baseline 75 nm	Extension 200 nm
Route Extension	4,200	1,400	4,100	1,500

Source: Brandsæter and Hoffman (2010 p. 7-103).

In summary, DNV's sensitivity analysis examines the effects of changes to four inputs on spill return periods. Results from the sensitivity analysis suggest that return periods change modestly compared to baseline return periods (Table A-12).

Table A-12: Summary of Sensitivity Analysis on Spill Return Periods (years)

Sensitivity Parameter	North Route	South Route via Caamano Sound	South Route via Browning Entrance
Baseline	**69**	**83**	**84**
Sensitivity 1: Increase in Scaling Factors for Grounding	59	71	71
Sensitivity 2: Increase in Traffic Density for Collisions	67	81	82
Sensitivity 3a: Decrease to 190 Tankers per year	80	96	97
Sensitivity 3b: Increase to 250 Tankers per year	61	73	74
Sensitivity 4: 200 nm Extension to Segments 5 and 8*	67	81	82

* DNV does not provide overall return periods for the trip extension sensitivity analysis and thus return periods were calculated based on Brandsæter and Hoffman (2010).

Mitigation Measures and Mitigated Spill Return Periods

The next step in the DNV analysis estimates the impact of various mitigation measures on spill return periods. DNV examines several risk reduction measures qualitatively including enhanced navigational aids, vessel traffic management system, environmental limits for safe operation, and the establishment of places of refuge along tanker routes. The marine shipping QRA only quantitatively evaluates a single mitigation measure: the tug escort plan.

DNV obtains the risk reducing effect of escort tugs from a confidential study it completed in 2002 and applies the downward adjustments directly to powered grounding, drift grounding, and collision incidents for the ENGP (Table A-13). DNV provides no details on the confidential study in the ENGP regulatory application.

Table A-13: Estimated Reduction in the Frequency of Incidents from Tug Use

Incident type	Condition	Reduction Effect
Powered Grounding	Laden with close and tethered tug	80%
	Laden with close escort	
	Ballast with close escort	
Drift Grounding	Laden with close and tethered tug	90%
	Laden with close escort	80%
	Ballast with close escort	
Collision	Laden or ballast with close and/or tethered escort	5%

Source: Brandsæter and Hoffman (2010 p. 8-120).

Table A-14 compares mitigated return periods to unmitigated return periods for oil or condensate spills. For all tanker spills, mitigation measures increase the spill return period from 78 years to 250 years. Mitigation measures for powered and drift grounding increase return periods by three- and four-fold, respectively. DNV does not identify mitigation measures for tanker foundering incidents and incidents involving fire and/or explosion.

Table A-14: Comparison of Unmitigated and Mitigated Oil/Condensate Spill Return Periods

Incident Type	Unmitigated Return Period (in years)	Mitigated Return Period (in years)
Powered Grounding*	107	480
Drift Grounding*	535	2,758
Collision*	1,084	1,138
Foundering*	25,821	25,821
Fire/ Explosion*	1,838	1,838
Total	**78**	**250**

Source: Brandsæter and Hoffman (2010).
* Calculated based on Brandsæter and Hoffman (2010).
Note: DNV does not identify mitigation measures for foundering and fire/explosion spills.

DNV also estimates the impact of mitigation measures on return periods by size of the spill. As shown in Table A-15, the use of tugs increases return periods from 200 to 550 years for an oil spill greater than 5,000 m^3.

Table A-15: Comparison of Unmitigated and Mitigated Return Periods for Various Oil Spill Sizes

Spill Volume (m^3)	Unmitigated Return Period (in years)	Mitigated Return Period (in years)
> 5,000	200	550
> 20,000	1,750	2,800
> 40,000	12,000	15,000

Source: Brandsæter and Hoffman (2010 p. 7-110; 137).

2. Spills from Operations at Kitimat Terminal

DNV determines spill return periods for particular types of incidents at Kitimat Terminal in the *Marine Shipping Quantitative Risk Analysis*. Furthermore, the Bercha

Group estimates risks from spills to the public and workers at the terminal in the *Northern Gateway Kitimat Terminal Quantitative Risk Analysis*.

Spill Return Periods for Incidents at Kitimat Terminal

DNV prepares a risk analysis examining the likelihood of spills at the marine terminal. Spill return periods for berthing/deberthing and cargo transfer operations at the marine terminal largely follow the methodology for tanker spills. The approach adopted by DNV estimates unmitigated and mitigated spill return periods at the marine terminal by:

- Determining base terminal incident frequencies
- Determining conditional spill probabilities from an assessment of consequences
- Estimating unmitigated spill return periods
- Identifying mitigation measures and applying measures in the calculation of mitigated spill return periods.

Base Incident Frequencies

DNV determines incident frequencies for berthing/deberthing and cargo transfer operations at the marine terminal based on LRFP data and DNV's research of operating terminals in Norway. According to DNV, "Incident frequencies from terminals in Norway are most representative of the operation planned for Kitimat Terminal and should provide an appropriate forecast of the possible incident frequency at the Kitimat Terminal" (Brandsæter and Hoffman 2010 p. 5-71). DNV provides no evidence to support the comparison between terminals in Norway and Kitimat Terminal.

DNV examines four types of potential incidents at the marine terminal:

1. A tanker is impacted by a harbour tug,
2. A tanker strikes the pier during berthing,
3. A tanker is impacted by a passing vessel, and
4. Various loading and/or discharging failures during cargo transfer operations.

According to DNV, the scenario whereby a tanker is impacted by a harbor tug is not applicable to the ENGP. Given the small mass of a 600-tonne tug boat, DNV claims that it will not achieve the speed of over 3.9 metres per second (7.6 knots) required to generate the 5 megajoules of energy required penetrate the hull of a tanker (Brandsæter and Hoffman 2010 p. 5-71). Therefore, DNV does not consider a tugboat colliding with a tanker in the marine shipping QRA.

In the event that a tanker strikes the pier during berthing, DNV assigns a base incident frequency of 6.3E-05 derived from LRFP data and world tanker operations. A tanker could strike the pier during berthing if tugs experience a mechanical failure or if human error results in a loss of control of the tanker or tug. According to DNV, this scenario is only applicable to tankers arriving at Kitimat Terminal and thus possible spills from a tanker striking the pier will be condensate and/or bunker fuel from laden condensate tankers or bunker fuel from oil tankers arriving to the terminal in ballast (Brandsæter and Hoffman 2010 p. 6-90).

For the third terminal incident type, DNV calculates the probability of a tanker being struck at berth by a passing vessel with downward adjustments to a base incident frequency. DNV estimates the frequency for a tanker being struck while at berth where B is a base frequency of 9.0E-06 obtained from DNV (2006), r_1 is a 10% reduction factor since Kitimat Terminal is not located in a high traffic port, r_2 is a second reduction factor of 50% to represent the effect of limited traffic forecast to pass Kitimat Terminal in the open Kitimat Harbour combined with tug boats used for berthing[33], t is the mean time of 30 hours for loading/discharging operations at Kitimat Terminal, and v is the number of vessels passing the terminal each year:

$$F_{striking} = B * r_1 * r_2 * [t / (365 * 24h)] * v$$

To adjust for the expected total number of tankers loading/discharging at Kitimat Terminal per year, DNV multiplies $F_{striking}$ by 220 to represent an expected frequency of 6.8E-05 per year for tanker traffic accessing Kitimat Terminal.

Finally, DNV estimates the probability of a spill from loading and discharge operations associated with cargo transfer operations based on its *Safety Analysis Handbook* (DNV 2000 as cited in Brandsæter and Hoffman 2010). Spill probabilities for cargo transfer operations represent several operational failures including overfilling of cargo tanks, damage to loading arms or piping from external impacts such as mooring failure and operator error, and leaks from loading arms or piping from internal impacts such as corrosion or fatigue (Brandsæter and Hoffman 2010 p. 5-74).

Conditional Probabilities

DNV determines the consequences of an incident during berthing/deberthing and cargo transfer operations. Similar to conditional probabilities estimated for tanker spills, conditional probabilities for terminal spills are the probability of a spill given that a terminal incident has occurred.

Table A-16 presents probabilities of a spill given that a tanker struck a pier during berthing or a passing vessel impacts a tanker. Consequences from a tanker striking the pier depend on where damage is inflicted on the tanker and if the damage results in penetration of the cargo or fuel tank. DNV suggests that impact from the marine structure is likely to result in penetrations to the hull above water and that, since it is assumed that small indents do not penetrate the outer hull, the conditional probability of a spill resulting in minor damage does not exist for laden tankers and tankers in ballast (Brandsæter and Hoffman 2010 p. 6-90). DNV estimates that the total conditional probability of a spill given a laden tanker and tanker in ballast strike the pier is 1% and 0.25%, respectively (Brandsæter and Hoffman 2010 p. 7-112).

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[33] DNV references a confidential document it prepared in 2006 as the source of this reduction. The confidential document is not appended to the marine shipping QRA and DNV provides no further information about the reduction factor.

In the event a tanker is struck by a passing vessel, vessels will be travelling at low speeds and although a tanker moored at Kitimat Terminal could be exposed to a side impact, a tanker is not likely to experience a perfectly perpendicular side impact (Brandsæter and Hoffman 2010 p. 6-91). DNV assumes that tankers moored at the marine terminal will be half full and thus the conditional probability of a spill is the average for laden vessels and vessels in ballast presented in Table A-16 for the tanker collision scenario (Brandsæter and Hoffman 2010). DNV predicts some release of cargo 11% of the time there is an impact by a passing vessel.

Table A-16: Damage Frequencies and Conditional Probabilities for Marine Terminal Incidents

Incident Type	Damage Category	LRFP Frequency Distribution (%)	Conditional Probability of Spill (%)	
			Laden	Ballast
Tanker Striking Pier	Minor	99	0	0
	Major	1	100	25
	Total Loss	Negligible	-	-
	Total Conditional Probability		**1**	**0.25**
Impact by Passing Vessel	Minor	74.5	0	
	Major	25.5	42.5	
	Total Loss	Negligible	100	
	Total Conditional Probability		**11**	

Source: Brandsæter and Hoffman (2010 p. 6-90 – 6-91).

Probabilities and distribution of cargo release per loading/discharging operation are summarized in Table A-17. DNV develops a spill size distribution for each event type from a review of historical databases from Norway and the UK and categorizes spill sizes according to the International Tanker Owners Pollution Federation Limited[34] (Brandsæter and Hoffman 2010 p. 6-91). DNV does not estimate large spills over 1,000 m^3 from an incident associated with cargo transfer operations.

Table A-17: Spill Probability and Spill Size Distribution for Cargo Transfer Operations

Event Type	Probability of Spill (per operation)	Distribution of Spill Size	
		Small (< 10 m^3)	Medium (10 – 1,000 m^3)
Release from Loading Arm	5.1E-05	90%	10%
Equipment Failure	5.1E-06	0%	100%
Failure in Vessels Piping System or Pumps	7.2E-06	90%	10%
Human Failure	7.2E-06	90%	10%
Mooring Failure	3.8E-06	0%	100%
Overloading of Cargo Tank*	1.2E-04	0%	100%

Source: Brandsæter and Hoffman (2010 p. 5-75) and DNV (2000) *as cited in* Brandsæter and Hoffman (2010 p. 6-92).
Note: Spill Probabilities represent loading and discharge for every event type with the exception of overloading of cargo tank.
* Overloading of cargo tank can only occur during loading operations.

The volume of oil spilled from cargo transfer operations depends on several factors. DNV uses the following equation to determine spill volumes from the failure of a single

[34] According to Brandsæter and Hoffman (2010 p. 6-91), the International Tanker Owners Pollution Federation Limited categorizes spills as follows: small spills (<7 tonnes ~ 10m^3); medium spills (7-700 tonnes ~ 10-1,000m^3); large spills (>700 tonnes ~ 1,000m^3).

loading arm where *V* is the volume spilled, *T* is the transfer rate, *dt* is the detection time and *E* is the emergency shutdown time (Brandsæter and Hoffman 2010):

$$V = T * (dt + E)$$

Based on the above equation, the failure of one loading arm operating at its full rate of transfer will result in different spill volumes for condensate and crude oil due to different transfer rates and emergency shutdown times. The failure of a single loading arm will result in a condensate spill of 200 m^3 or a crude oil spill of 250 m^3 (Brandsæter and Hoffman 2010 p. 6-92)[35].

Unmitigated Spill Return Periods

DNV combines incident frequencies and conditional probabilities to determine the unmitigated risk evaluation of incidents at the marine terminal. Unmitigated risk is presented as return periods for spills and is calculated based on forecast tanker traffic calls to Kitimat Terminal and, where applicable, spill size distributions for particular incident types.

In the event that a tanker strikes the pier during berthing, DNV claims that energy produced from impacts to the pier is not sufficient to penetrate the outer or inner hull of a tanker and thus results in a low likelihood that a spill will result from a striking incident (Brandsæter and Hoffman 2010 p. 7-112). DNV estimates that a crude tanker in ballast or laden condensate tanker will strike the pier at Kitimat Terminal once in 72 years, whereas a tanker striking the pier and spilling cargo will occur only once in 14,600 years (Table A-18).

Table A-18: Frequency and Return Periods for a Tanker Striking the Pier During Berthing

Cargo Type	Number of Approaches	Strikings per Year	Striking Return Period** (in years)	Spill Frequency per Year	Spill Return Period (in years)
Crude*	149	9.4E-03	107	2.4E-05	42,600
Condensate	71	4.5E-03	224	4.5E-05	22,300
Total	**220**	**1.4E-02**	**72**	**6.8E-05**	**14,600**

Source: Brandsæter and Hoffman (2010 p. 7-112).
Figures might not add due to rounding.
* A release of crude includes the possible release of bunker fuel.
** Return periods for striking incidents are calculated based on the number of strikings per year.

With regards to a tanker impact by a passing vessel, DNV claims that the unmitigated risk is "very low" (Brandsæter and Hoffman 2010 p. 7-112) due to the low volume of vessel traffic passing Kitimat Terminal. To support this claim, DNV multiplies the annual frequency of 6.8E-05 per year by the conditional probability of 11% to obtain the annual probability of 7.3E-06 for a tanker impact by a passing vessel that results in

[35] DNV bases spill volumes of 200 m^3 of condensate and 250 m^3 of crude oil on a transfer rate of 3,000 m^3 per hour for condensate and 4,000 m^3 per hour for crude oil, a 180 second detection time for both products, and an emergency shutdown time of 60 seconds for condensate and 40 seconds for crude oil (Brandsæter and Hoffman 2010 p. 6-92).

a spill. Expressed as a return period, a spill from a tanker being struck by a passing vessel will occur once every 130,000 years (Brandsæter and Hoffman 2010 p. 7-112).

DNV bases unmitigated return periods for oil/condensate spills on the loading/discharging of 220 tankers[36] and estimates unmitigated return periods for oil spills according to the 149 oil tankers to call at Kitimat Terminal. As shown in Table A-19, DNV estimates that unmitigated small or medium size oil/condensate spills from cargo transfer operations will occur once every 29 years, whereas a small or medium size oil spill will occur every 34 years (Brandsæter and Hoffman 2010 p. 7-113; 136).

Table A-19: Unmitigated Return Periods for Oil/Condensate and Oil Spills from Cargo Transfer Operations

Cargo Transfer Operation		**Unmitigated Return Period** (in years)		
		Small	**Medium**	**Overall**
Release from Loading Arm	Oil/Condensate	99	890	89
	Oil Only*	146	1,316	132
Equipment Failure	Oil/Condensate	-	890	890
	Oil Only*	-	1,316	1,316
Failure in Vessels Piping System or Pumps	Oil/Condensate	700	6,300	630
	Oil Only*	1,036	9,321	932
Human Failure	Oil/Condensate	700	6,300	630
	Oil Only*	1,036	9,321	932
Mooring Failure	Oil/Condensate	-	1,100	1,100
	Oil Only*	-	1,766	1,766
Overloading of Cargo Tank	Oil/Condensate	-	56	56
	Oil Only*	-	56	56
Total	**Oil/Condensate**	**77**	**46**	**29**
	Oil Only	**110**	**49**	**34**

Source: Brandsæter and Hoffman (2010 p. 7-113; 136).
* Return periods for oil spills are calculated with information from Brandsæter and Hoffman (2010).
Note: Small spills represent spills < 10 m^3 and medium spills represent spills from 10 to 1,000 m^3.

Mitigation Measures and Mitigated Spill Return Periods

DNV applies mitigation measures to its unmitigated risk evaluation and recalculates return periods for spills at the marine terminal. DNV quantitatively evaluates a closed loading system with vapour recovery as the principal mitigation measure for spills at the marine terminal. According to DNV, a closed loading system and vapour recovery unit will "virtually eliminate tank overfilling" (Brandsæter and Hoffman 2010 p. 131) thus reducing a spill to a negligible risk.

Table A-20 presents mitigated return periods for oil/condensate and oil spills for cargo transfer operations. According to DNV, a closed loading system and vapour recovery unit installed at Kitimat Terminal can redirect excess oil from overfilled cargo tanks into alternate ship tanks (Brandsæter and Hoffman 2010 p. 131). In the event that oil is spilled by overloading cargo tanks and not recovered by the vapour return system, the

[36] According to DNV, The only exception is the event in which cargo tanks are overloaded since the tanks can only be overfilled during loading operations.

deck containment system would capture and direct the excess oil to vessel slop tanks (Brandsæter and Hoffman 2010 p. 131). DNV claims that the closed loading system and vapour recovery unit will eliminate any risk of an oil spill associated with overloading cargo tanks and thus the probability per year of this event occurring drops to zero (Brandsæter and Hoffman 2010 p. 131).

Table A-20: Mitigated Return Periods for Oil/Condensate and Oil Spills from Cargo Transfer Operations

Cargo Transfer Operation		Mitigated Return Period (in years)		
		Small	**Medium**	**Overall**
Release from Loading Arm	Oil/Condensate	99	891	89
	Oil Only*	146	1,316	132
Equipment Failure	Oil/Condensate	-	891	891
	Oil Only*	-	1,316	1,316
Failure in Vessels Piping System or Pumps	Oil/Condensate	701	6,313	631
	Oil Only*	1,036	9,321	932
Human Failure	Oil/Condensate	701	6,313	631
	Oil Only*	1,036	9,321	932
Mooring Failure	Oil/Condensate	-	1,196	1,196
	Oil Only*	-	1,766	1,766
Overloading of Cargo Tank	Oil/Condensate	-	-	-
	Oil Only*	-	-	-
Total	**Oil/Condensate**	**77**	**294**	**62**
	Oil Only	**110**	**430**	**90**

Source: Brandsæter and Hoffman (2010 p. 132; 136).
* Return periods for oil spills are calculated with information from Brandsæter and Hoffman (2010).
Note: Small spills represent spills < 10 m^3 and medium spills represent spills from 10 to 1,000 m^3.

Table A-21 compares the effects of mitigation measures for cargo transfer operations to overall unmitigated spill return periods. According to DNV, mitigation measures more than double the return period for unmitigated oil/condensate spills from 29 to 62 years.

Table A-21: Comparison of Overall Unmitigated and Mitigated Oil/Condensate Spill Return Periods for Cargo Transfer Operations

Cargo Transfer Operation	Unmitigated Return Period (in years)	Mitigated Return Period (in years)
Release from Loading Arm	89	89
Equipment Failure	891	891
Failure in Vessels Piping System or Pumps	631	631
Human Failure	631	631
Mooring Failure	1,196	1,196
Overloading of Cargo Tank*	56	n/a
Total	**29**	**62**

Source: Brandsæter and Hoffman (2010).

Rupture Failure Frequencies for Components at Kitimat Terminal

The Bercha Group (2012a) prepared a risk analysis report examining spills associated with operations at the marine terminal. The Bercha Group submitted the report in May

2012 as a response to an information request from the Joint Review Panel for the ENGP (MacDonald 2012). The risk assessment examines worker and public safety at the marine terminal measured according to the risk to individuals exposed to oil or condensate releases (Bercha Group 2012a). The report does not examine risks to the environment or property surrounding the terminal.

The risk analysis uses a methodological approach that includes identifying hazard scenarios, determining failure frequencies that result in a spill, evaluating the consequences of spills, assessing risks, and recommending measures to mitigate risk (Bercha Group 2012a). The risk analysis examines failure frequencies that include the following terminal components: piping, pumps, storage tanks, and loading/unloading arms (Bercha Group 2012a). Based on calculations from the Bercha Group report, return period for a rupture from one of the terminal components is 282 years (Table A-22). The volume of oil or condensate spilled from a leak or full rupture at one of the terminal components ranges between 10 m^3 and 80,000 m^3 depending on the type of terminal component affected, the number of terminal components involved, and other assumptions used by the Bercha group to model failure frequencies at the marine terminal (Bercha Group 2012a).

Table A-22: Rupture Failure Frequencies for Marine Terminal Components

Component	Rupture Failure Frequency	Estimated Return Period (in years)*
Piping	1.00E-07	10,000,000
Pumps	1.00E-04	10,000
Oil Tanks	5.50E-05	18,182
Condensate Tanks	1.50E-05	66,667
Loading Arm - Oil	2.29E-03	437
Unloading Arm - Condensate	1.09E-03	917
Total*	**3.55E-03**	**282**

Source: Bercha Group (2012a p. 4.4).
* We calculate return periods based on information and data from Bercha Group (2012a).

The Bercha Group (2012a) concludes that risks to individuals from operations at the marine terminal are within tolerable limits. Based on Individual Specific Risks thresholds, the authors determine that risks to the public in the area surrounding the terminal are insignificant at less than one in one million, while risks to workers are higher although tolerable at a range of between one in 10,000 and one in 100,000. The authors recommend mitigation measures to ensure safe operational and work procedures at the marine terminal.

3. Spills from Onshore Pipeline Operations

The ENGP regulatory application contains several pipeline spill estimates. In its regulatory application submitted in 2010, Enbridge prepared a section in Volume 7B estimating return periods for spills that occur along the pipeline route. In 2012, WorleyParsons and the Bercha Group submitted additional risk analyses estimating pipeline spill likelihood for the project.

Spill Return Periods for Medium and Large Spills

Volume 7B of the Enbridge application identifies return periods for a hydrocarbon[37] release that occurs along the pipeline route. Enbridge calculates spill return periods with liquid pipeline failure frequency data from 1991 to 2009 from the National Energy Board (NEB). According to Enbridge, NEB data best represent the ENGP because data are based on hydrocarbon transmission lines under the jurisdiction of the NEB (Enbridge 2010b Vol. 7B, p. 3-1). Enbridge notes that NEB data include pipelines up to 50 years old that use older technology and building material standards associated with an increased frequency of failures compared to modern pipelines (Enbridge 2010b Vol. 7B, p. 3-1). Accordingly, Enbridge factored improved design features and mitigation planning characteristic of modern pipelines into its failure frequency calculations. Improvement factors are expected to decrease the probability of pipeline failure relative to NEB failure frequency data (Enbridge 2010b Vol. 7B, p. 3-1). The ENGP pipeline spill analysis does not provide the original or adjusted NEB spill data that was used in the analysis, does not document the adjustments made to the NEB data and provides no evidence to support the downward adjustment of NEB spill rates for the ENGP.

Enbridge estimates return periods for various spill size categories of hydrocarbon releases for six regions along the pipeline route. Enbridge bases spill size categories on NEB classifications whereby a small spill is less than 30 m^3, a medium spill ranges between 30 and 1,000 m^3, and a large spill exceeds 1,000 m^3 (Enbridge 2010b Vol. 7B). Enbridge identifies the six physiographic regions along the pipeline route as the Eastern Alberta Plains, the Southern Alberta Uplands, Alberta Plateau, Rocky Mountains, Interior Plateau, and the Coast Mountains.

Table A-23 presents spill return periods calculated by Enbridge for medium and large spills in the six regions. Based on the adjusted NEB frequency data, spill return periods for medium spills range between 118 and 1,082 years for each physiographic region, while spill return periods for large spills range between 275 and 2,525 years per region. Enbridge does not combine spill return periods for the six regions nor does it combine return periods for medium and large spills. Combined, the six regions result in spill return periods for medium and large spills of 41 and 95 years, respectively, for the entire pipeline route. Similarly, combining overall return periods for medium and large spills for the entire length of the pipeline results in a return period of 28 years. Enbridge neither estimates nor presents spill return periods for small spills, yet simply states “Smaller releases (less than 30 m^3) occur more frequently” (Enbridge 2010b Vol. 7B, p. 3-2).

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[37] Enbridge (2010b Vol. 7B p. 3-1) refers to pipeline spills as hydrocarbon spills. We interpret hydrocarbon spills to include both oil and condensate and thus assume spill return periods represent oil or condensate spills.

Table A-23: Return Periods for Spills from the Northern Gateway Pipeline

Physiographic Region	Approximate Pipeline Length (km)	Spill Return Period (in years)	
		Medium	Large
Eastern Alberta Plains	166	287	669
Southern Alberta Plains	350	136	317
Alberta Plateau	44	1,082	2,525
Rocky Mountains	103	462	1,079
Interior Plateau	404	118	275
Coast Mountains	105	454	1,058
Total*	**1,172**	**41**	**95**
Combined Medium and Large Spills**		**28**	

Source: Based on Enbridge (2010b Vol. 7B p. 3-2).
* We combine spill return periods for each segment to represent the spill return period for the entire pipeline route.
** We combine return periods for medium and large spills into a single return period based on information provided in *Volume 7B* of the ENGP regulatory application.
Note: Medium spills represent spills from 30 to 1,000 m^3 and large spills represent spills > 1,000 m^3.

Spill Return Periods for Pipeline Ruptures Resulting in an Uncontrolled Spill

In addition to *Volume 7B*, Enbridge contracted WorleyParsons to prepare a risk assessment evaluating the likelihood of a pipeline rupture that releases dilbit in an unconstrained manner (referred to as full-bore spill) (WorleyParsons 2012). The report entitled *Semi-Quantitative Risk Assessment* uses the following approach to evaluating risk:

- Identify hazards that threaten the integrity of the pipeline system
- Estimate failure frequencies based on failure frequency modeling and expert judgment
- Determine areas along the pipeline that have higher consequences from a full-bore rupture
- Examine the severity of unmitigated risk based on the frequency and consequence of the rupture (WorleyParsons 2012).

The WorleyParsons (2012) report determines spill frequencies for leaks and full-bore pipeline ruptures over the length of the ENGP pipeline[38]. The analysis uses several methodological approaches and datasets including a failure frequency model that uses data from recently constructed pipelines, particularly Enbridge Line 4, as well as pipeline spill data from the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) from 2002 to 2009 (WorleyParsons 2012). The report evaluates eight hazards related to pipeline ruptures including internal corrosion, external corrosion, materials and manufacturing defects, construction defects, equipment failure, incorrect operations, damage from third parties, and geotechnical and hydrological threats (Table A-24). The WorleyParsons report determines that the probability of a 594-bbl (94 m^3) oil pipeline leak is 0.249, which results in a return period of 4 years. For full-bore ruptures releasing oil in an unconstrained manner, the WorleyParsons report estimates an annual probability of 0.0042 (return period of 239 years) for a pipeline rupture releasing 14,099 bbl (2,242

[38] We acknowledge that the pipeline distance of 1,176 km used in the WorleyParsons report differs from the 1,172 km used in *Volume 7B* of the ENGP regulatory application. Neither report addresses the discrepancy.

m³) of oil. In addition to estimating oil spills, WorleyParsons estimates return periods for a 593 bbl (94 m³) condensate leak of 4 years and a 5,183 bbl (823 m³) condensate rupture of 273 years.

Table A-24: Return Periods for Leaks and Full-bore Ruptures

Pipeline Hazard	Return Period (in years)			
	Oil Pipeline		Condensate Pipeline	
	Leak	Rupture	Leak	Rupture
Internal corrosion	0	0	0	0
External corrosion	0	0	0	0
Materials and manufacturing defects	652	652	652	652
Construction defects	39	0	39	0
Equipment failure	5	0	5	0
Incorrect operations	47	0	47	0
Damage from third parties	436	1,308	1,385	4,149
Geotechnical and hydrological threats	0	530	0	530
Total	**4**	**239**	**4**	**273**

Source: WorleyParsons (2012); WorleyParsons (2012 as cited in WrightMansell 2012)

WorleyParsons also identifies areas along the pipeline corridor that are likely to suffer higher consequences in the event of a full-bore pipeline rupture (Table A-25). According WorleyParsons (2012), the six areas of high consequence represent a total of 181 km of the 1,176 km ENGP, or approximately 15%, and a rupture is forecast to occur in a high consequence area once every 1,260 years. Based on return periods, Kitimat River is the most likely area affected by an unconstrained rupture due to geohazards in the region. According to WorleyParsons (2012 p. 34), geohazards represent the most significant threat to the Northern Gateway pipeline system.

Table A-25: Return Periods for a Full-bore Pipeline Rupture in High Consequence Areas

High Consequence Area	Length of Pipeline Affected (in km)	Return Period (in years)
Kitimat River	29	2,200
Athabasca River	32	12,000
Smoky River	33	12,000
Missinka River	41	14,000
Morice River	24	16,000
Gosnell River	22	24,000
Total	**181**	**1,260***

Source: WorleyParsons (2012 p. 29).
* We estimate the total return period for all six high consequence areas.

Failure Frequencies for Pump Stations and Ruptures Along in Densely Populated Areas

The Bercha Group prepared two risk assessments examining separate risks from pump stations and pipeline ruptures associated with the ENGP pipeline. Both studies use a similar methodological approach that includes determining hazards, assessing the frequency of occurrence of a spill, evaluating spill consequences, assessing risk, and identifying mitigation measures that reduce risk (Bercha Group 2012b; 1012c).

The first Bercha Group (2012c) study assesses worker and public safety risks from an oil or condensate spill at Smoky River Station, the largest pump station along the pipeline route in Alberta near Grande Prairie. Table A-26 shows the failure frequencies per year for combined piping and pump spills at the Smoky River Station. The Bercha Group obtained piping and pump failure frequencies from a report entitled *Guidelines for Quantitative Risk Assessment* produced by Ministry of Housing, Spatial Planning and the Environment in the Netherlands and uses incident statistics from the most recent decade of data (Bercha Group 2012c p. 4.1). Based on failure frequencies, the return periods for oil or condensate leaks or ruptures range between 332 and 4,082 years. To estimate consequences of spills at Smoky River station, the Bercha Group (2012c) estimates the amount of oil and condensate leaked from a spill at 50 m^3 and the amount of oil or condensate released as a result of a rupture at 300 m^3 or 1,000 m^3, respectively. From its frequency and consequence assessment, the Bercha Group (2012c) concludes that individual risks from oil or condensate leaks and ruptures are within allowable limits.

Table A-26: Frequencies for Piping and Pump Spills at Smoky River Station

Type of Spill	Failure Frequency (per year)	Return Period (in years)*	Release Volume (m^3)
Oil Leak	3.01E-03	332	50
Oil Rupture	6.02E-04	1,661	1,000
Condensate Leak	1.22E-03	820	50
Condensate Rupture	2.45E-04	4,082	300

Source: Bercha Group (2012c).
* Calculated from Bercha Group (2012c).

The second Bercha Group (2012b) study identifies areas along the pipeline route that are known to have high public concentrations and determines the risk to individuals of a pipeline spill at those locations. The authors identify three heavily populated areas that could be affected by a pipeline spill: A casino near Whitecourt, AB; Burns Lake, BC; and Kitimat, BC.

To estimate public risk from a pipeline spill, the Bercha Group (2012b) estimates the failure frequency of the ENGP pipeline based on historical pipeline rupture data from the NEB from 1991 to 2009 and makes several adjustments to the data to incorporate various improvements in pipeline operations. As shown in Table A-27, the failure rate of 0.372 per 10,000 km per year (10,000 km-year) based on NEB historical data decreases significantly to 0.109 spills per 10,000 km-year due to numerous downward adjustments ranging from 60 to 90%. The Bercha Group (2012b) concludes that risks to public safety from a pipeline failure near the Casino at Whitecourt, Burns Lake, and Kitimat are insignificant. Risks to residents and indoor and outdoor workers from a pipeline releasing oil, condensate, or both are all below one in one million per year, which the Bercha Group determines are acceptable levels of risk (Bercha Group 2012b).

Table A-27: NEB Pipeline Failure Frequencies Adjusted Downward to Represent the ENGP

Pipeline Failure Causes	**NEB Failure Rate** (per 10,000 km-year)	**ENGP Failure Rate** (per 10,000 km-year)	**Downward Adjustment**	**Reason for Adjustment**
Metal Loss	0.085	0.017	80%	Modern piggable pipelines are less likely to fail than pipelines represented in NEB data
Cracking	0.128	0.013	90%	Advanced coating technologies, low stress design, and fatigue avoidance through design and operations
External Interference	0.021	0.021	-	n/a
Geotechnical Failure	0.021	0.021	-	n/a
Material Failure	0.021	0.009	60%	Construction quality control, inspection/testing after construction, and operational surveillance
Other Causes	0.096	0.028	71%	Estimated as same percentage as NEB data (approx. 26%)
Total	**0.372**	**0.109**	**71%**	

Source: Bercha Group (2012b).