Accufacts Inc.
"Clear Knowledge in the Over Information Age"

Report on Pipeline Safety for Enbridge's Line 9B Application to NEB

August 5, 2013

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Appendix – Exhibits Referenced in Report

I. Executive Summary

Accufacts was asked to provide an independent analysis regarding pipeline safety concerning the Line 9B Reversal and Line 9 Capacity Expansion Project Application and related documents filed to the National Energy Board ("NEB" or "Board") by Enbridge, including their Pipeline Integrity Engineering Assessment, as well as related Information Requests and Enbridge Responses (collectively referenced in this report as the "Project").[1] The Project basically makes pump station modifications to reverse the flow of an existing 30-inch Line 9B pipeline segment routed through southeastern Canada from the North Westover Pump Station in Ontario to the Montreal Terminal in Quebec. The applicant, Enbridge, is asking to link up and increase the capacity of a previously NEB approved Line 9A proposal (an earlier similar 30-inch pipeline reversal from Sarnia, Ontario to North Westover, Ontario). The applicant is now asking to be permitted to move a wide range of crude oils, including heavy oil that includes various forms of diluted Canadian tar sands bitumen, or dilbit, as well as light crudes such as Bakken, eastward on the 9A and 9B segments. The Project directly concerns only pipeline assets within Canada, and is thus governed by Canadian approval processes and pipeline safety regulations, falling under the jurisdiction of the NEB. The Project, however, could also have an impact on several major pipelines operating in the U.S. connecting to the Sarnia, Ontario and Montreal, Quebec Terminals.[2] It is hoped this report will assist the NEB in making its decision.

Enbridge has claimed they are one of the largest users of inline inspection ("ILI"), or smart pig technology, so it is surprising that their crack assessment tool use, verification, and integration into their IM program is proving inadequate, even after Enbridge's Marshall, MI 30-inch Line 6B pipeline rupture. The many shortcomings in Enbridge's IM crack threat assessment program, discovered from investigation of various public records following the July 25, 2010 Marshall, MI rupture from Stress Corrosion Cracking ("SCC"), are discussed. Like Line 6B, both Line 9A and Line 9B are 30-inch pipelines exhibiting extensive SCC coincidental with general corrosion pipe wall loss from severely disbonded polyethylene external coating. Such cracking threats are prevalent along the system, appear to pose the greatest threat to pipeline integrity, and are proving very challenging to identify or assess via ILI and engineering assessments. Public records make it very clear that Enbridge is still not heeding pipeline investigators/regulators in IM, nor has Enbridge adequately incorporated the critical safety process management perspectives that serve as the basis of prudent pipeline IM regulation to assure safety. Given these still serious IM deficiencies, especially in the ILI crack management program, in order to substantially reduce the risk from crack rupture, Accufacts must now recommend that hydrotests

[1] "Line 9B Reversal and Line 9 Capacity Expansion Project Application by Enbridge Pipelines Inc.," Filed with the National Energy Board, major files NEB web site at https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=890819&objAction=browse.

[2] Canadian Energy Pipeline Association ("CEPA"), "Liquid Pipelines," at website http://hamiltonline9.files.wordpress.com/2012/08/na-pipeline-map.jpg.

be performed on both Line 9A and Line 9B to verify the pipeline's integrity and current fitness for its new service. Accufacts must conclude, given our extensive experience in pipeline risk management and the information provided in this report indicating continuing serious deficiencies still in Enbridge's IM approach, that without a proper hydrotest there is a high risk the pipeline will rupture in the early years following the Project's implementation.

Recommended hydrotesting should obviously be performed to Canadian standards that are superior in their prescriptive requirements compared to U.S. pipeline safety hydrotesting regulations. Canada has a long history and considerable experience in assuring performance of such proper hydrotesting of pipelines containing extensive cracking risks, such as SCC. Accufacts further concludes that Enbridge statements suggesting that such hydrotests can damage a transmission pipeline, or be dangerous to the pipeline, are without technical merit, and appear to be attempts to misinform decision makers and the public.

As also explained in this report, substantial improvements in Enbridge's leak detection approach are also warranted as Enbridge has not demonstrated they understand the weaknesses of the Mass Balance System ("MBS") approach that played a major role in the more than 17 hours it took to recognize that a rupture at Marshall, MI had occurred, and close proper remote operated isolation valves. Leak detection improvements should focus on rapid identification of rupture, even during transients. In the area of rupture detection, history has repeatedly demonstrated just meeting "industry standards" will not prove sufficient. Accufacts advises that simple operational changes should also be implemented to eliminate the potential of slack line during transient and normal operation on Line 9, and additional efforts focused to significantly reduce false MBS alarms to the Control Room. Based on Accufacts' extensive experience in pipeline leak detection, control room management regulatory development, and pipeline incident investigation, current estimated oil spill volumes indicated in the Project are most likely significantly understated. In addition, in the event of a release, claimed Enbridge response times in various IR responses of 1.5 to 4 hours for such a high consequence pipeline system as Line 9B are also not adequate or appropriate.[3]

Section VIII summarizes Accufacts' twelve main conclusions and three specific recommendations to the NEB concerning the Enbridge Project.

[3] For example, see Enbridge responses to Toronto or Ontario, IR No. 2.

II. Brief Review of Enbridge Line 9 Project Proposal

Exhibit 1 is a system map of the Line 9 Project taken from Enbridge's Pipeline Integrity Engineering Assessment ("EA").[4] The Project builds from a previously NEB approved reversal and expansion for the approximately 120 mile (~ 194 kilometer) Line 9A segment from Sarnia, Ontario (Milepost, or "MP", ~ 1742) to North Westover Station, Ontario (MP ~ 1862.6). The Project consists of an additional approximately 397 mile (~ 636 kilometer) Line 9B segment from North Westover station to the Montreal Terminal (~ MP 2259.6) in Quebec, also reversing previous flow operation in this segment to move eastward. This Project will also increase the design capacity on the entire Line 9 system (Sarnia to Montreal Terminal) to approximately 333,000 bbls/d utilizing DRA at each pump station).[5] The original Project application indicated an annual rate of 300,000 bbls/d, but subsequent filings indicate a higher stream day rate design capacity using existing pump station sites, as indicated in Table 1 below, with DRA injection at various pump stations.[6]

Table 1 – Main Station Facility MP Locations for Line 9

Main Station Facilities	MP	Delta Mileage to Nearest Downstream Line 9 Station
Sarnia Pump Station (SA)	**1742**	
North Westover Pump Station (NW)	**~1862.6**	**120.6**
Hilton Pump Station (HL)	**~1997.3**	**134.7**
Cardinal Pump Station (CD)	**~2131.6**	**134.3**
Terrebonne Station (No pumping)	**~2247.8**	**116.2**
Montreal Terminal (MT)	**~2259.6**	**12**
	Total (SA – MT)	**517.8**

4 Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," Submitted to National Energy Board, November 2012, "Figure 2.1 – The Project System Map," p. 11.

5 Drag Reducing Agent, or DRA, is an additive injected in certain locations along a pipeline to reduce energy loss due to fluid turbulence. Sudden loss of DRA injection may seriously affect liquid velocity and possible surge pressures within a pipeline.

6 Enbridge Pipeline Inc., Line 9B Reversal and Line 9 Capacity Expansion Project, "Mainline Transient Analysis Summary Report," June 2013, p. 4.

With the exception of some possible "temporary" workspace sites, the Project will mainly involve construction activities modifying existing pump stations on current Enbridge properties and rights-of-way. While the project is designed to operate at higher pressures than current westward flow, the MOP of the pipeline will not change from that last established by a hydrotest in 1997. The Project is designed for higher throughput and is asking the NEB for approval to also move heavy Canadian (most likely containing blended tar sands oils, aka dilbit), as well as lighter crude oils from the Western Canadian and U.S. Bakken region eastward along the entire Line 9 system, both the Line 9A and 9B segments.[7] In approving the Line 9A project in 2012 the NEB had limited the Line 9A segment to shipping only light and medium crude oils, subject to a reapplication.[8] Once modified, Line 9 will be designed to flow in only one direction, eastward.[9]

The mainline pipe, outside of the pump stations, in segment 9B consists of 30-inch (762 mm) diameter, X-52 grade, Double Submerged Arc Weld (DSAW) pipe, ranging in thickness from 0.25 inch (6.35 mm) to 0.5 inch (12.7 mm) with approximately 97 % of the mainline pipe equal to or less than 7.92 mm thick (0.250, 0.281, and .312 inches thick).[10] The pipeline was installed in 1975 and is externally coated with polyethylene tape, a tape coating that can seriously disbond or separate from the pipe wall to introduce the threat of SCC in certain environments. This type of coating has a tendency to "tent" near the longitudinal manufacturing seam, generating areas where fields of SCC colonies or "crack-fields" in sites of extensive general corrosion that further reduce pipe thickness under the tenting (see Exhibit 2 –SCC colonies/clusters in areas of general corrosion wall loss on the pipe joint that ruptured in Marshall, MI). What can make Fitness for Service time to failure predictions associated with SCC unpredictable in such conditions is that the SCC colonies can interact or quickly link up in sufficient depth and length within the area of general corrosion in an unpredictable manner, causing the pipe to rupture well before Fitness for Service or engineering assessment time estimates. These extensive SCC sites can also be at risk from another form of environmentally associated cracking, corrosion fatigue cracking, which to the naked eye looks similar to SCC, but is also driven by similar growth mechanisms such as pressure cycling. SCC, corrosion-fatigue, and general corrosion can also interact to accelerate time to failure. Based on the information supplied in the Project's EA, it is fair to assume that

[7] "Line 9B Reversal and Line 9 Capacity Expansion Project Application by Enbridge Pipelines Inc.," filed with the NEB, p. 24.
[8] NEB Letter Decision, "Enbridge Pipelines Inc. (Enbridge) Line 9 Reversal Phase I Project (Project) Hearing Order OH-005-2011," 27 July 2012, p. 27.
[9] Enbridge Response to Stragetgies Energetiques Information Request No. 2 OH-002-2013 File OF-Fac-Oil-E101-2012-10 02, "IR 2.2.m," p. 10.
[10] Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," submitted to National Energy Board, November 2012, p. 14.

both Line 9A and 9B segments have extensive crack threat sites, such as SCC, similar to those observed in Line 6B across that system.[11]

III. Critical Factors in Previous Accufacts Line 9A Phase I Reversal Report on Enbridge's Methods

Several observations from my earlier report on Line 9A are, in my opinion, very relevant to the current Project.[12] I do not mean to over work these points, but the Project's application clearly demonstrates these issues still apply very much to the Project. Briefly highlighted are these important considerations:

1) For Cracks threats, ILI unity plots showing what the ILI tool actually measures is critical

For cracks, unity plots (a plot of the field dig readings versus pig indication) for both crack depth and crack length are critical to allow a direct comparison by engineers and regulators of the results provided by the pig vendor. In addition, special consideration should be paid to crack location and multiple crack fields associated with disbonded coating, especially in proximity to the manufacturing seam weld where "tenting" can occur.

Given the misapplications of the IM processes uncovered by the NTSB investigation of the Enbridge Marshall, MI rupture, crack ILI unity plots should not be plotted as predicted failure pressure ratio ("PFPR"). This is even more important given the problems discovered with the crack predicted failure pressure ratio approach and ILI performance by the NTSB, but also the Fitness for Service (aka Fitness for Purpose) methods that Enbridge utilized. Enbridge's current approach appears to still contain many of the biases that could result in non-conservative prediction in identifying crack threats. The Board should require Enbridge to supplement Figures 4.38 though 4.43 with additional unity plots for crack length that would allow an independent audit that would uncover any serious shortcomings in Fitness for Service engineering assessment approaches that are not conservative (See Exhibit 3 - Table of remaining strength calculations for 51.6 inch long feature that ruptured in Marshall MI using various wall thicknesses and ILI tool tolerances).[13]

Enbridge was using, and still maintains to this day, that their Fitness for Service approach should not use actual wall thickness measurements in crack fields such as SCC (See Exhibit 2 SCC colonies/clusters in areas of general corrosion wall loss on the pipe joint that ruptured in Marshall, MI), despite repeated wall measurement ILIs indicating substantially less wall

[11] Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," Submitted to National Energy Board, November 2012, pp. 57 – 59.
[12] Accufacts Inc., "Accufacts' Perspective on Enbridge Filing for Modification on Line 9 Reversal Phase I Project," April 23, 2012.
[13] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study for Marshall, MI, Report No. 12-046," 4-20-12, p. 4.

thickness in areas with wall thinning in the SCC crack field. It is also worth mentioning that the depth figures for the ILI crack tool run indicate a non-conservative bias (underreporting the depth of SCC cracks in the 2004/2005/2006 USCD crack ILI tool evaluation) which is consistent with the findings of the NTSB in their Line 6B investigation of the 2005 USCD ILI tool run. Plots of Predicted Failure Pressure Ratios (PFPRs) can hide many shortcomings in a crack's actual ability to withstand operating pressure. A review of Exhibit 3 (Table of remaining strength calculations for 51.6 inch long feature that ruptured in Marshall MI using various wall thicknesses and ILI tool tolerances), produced at the request of the NTSB) clearly demonstrates why the Marshall rupture failed well below MOP and even below Enbridge's self imposed pressure reduction.

2) Low pressure operation should never be used as credit in an IM program

Accufacts previously warned that pressure reduction should not be relied upon as a "safety" in pipeline operation for various reasons. Regulations, for example, permit operators to periodically exceed the Maximum Operating Pressure ("MOP"), especially during surges, such as those associated with changing crude slates or emergency upsets. It should be noted that the Board wisely stated in their approval of the Line 9A proposal that "The Board is of the view that, if a pipeline is not able to operate safely at its approved MOP of existing pressure, a pressure reduction may be a temporary solution. Ultimately, repair of any features affecting the integrity of the pipeline is the only permanent solution."[14] From Accufacts' perspective the Board understands the importance of not taking integrity credit for lower pressure operation.

As a point of reference, the Marshall, MI pipe joint that ruptured, failed at a pressure of approximately 56% SMYS or less, while operating under an Enbridge self imposed pressure reduction of 60% SMYS for approximately one year. The pipeline had a MOP of 72 % SMYS.

3) Possible effects of changing crude slate

When crack threats pose a significant threat to a pipeline, pressure cycling is an important consideration requiring accurate and thorough evaluation. Pressure cycling has the ability to seriously affect, vary, and accelerate crack growth rates. Special care should be taken to assure that field measurements for cracks do not unduly understate pressure cycling spectrums and are representative of actual and future operation. Accufacts has observed many failures where the pressure cycle spectrum was classified at a lower spectrum when actual failures were caused by much more aggressive cycling. It is very easy to use the wrong spectrum on engineering assessments, resulting in serious underestimating of time to failures with premature failure, usually below MOP. Changing crude slates, especially running dilbit, can significantly increase pressure cycles that can accelerate crack growth. The various and changing compositions of dilbit, both the bitumen and/or the diluent, can significantly impact pressure cycles on a pipeline where crack risk is a bona fide threat. Accufacts believes that the movement of dilbit in pipelines at risk to cracking threats presents a higher potential to cause pipeline ruptures if not adequately managed.

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[14] NEB Letter Decision, "Enbridge Pipelines Inc. (Enbridge) Line 9 Reversal Phase I Project (Project) Hearing Order OH-005-2011," 27 July 2012, p. 25.

4) Valve analysis and surge analysis for over pressure protection

Given its significance in a liquid pipeline rupture as well as many IR requests related to valving, Accufacts believes it is worth commenting further on the issue of valves building off my observation on the earlier 9A filing.[15] It is my opinion that Enbridge, on the subject of valves in the Line 9 Project's application is showing itself to be an industry leader in this area. This opinion is subject to several caveats uncovered from the Marshall, MI incident investigations.

1. Automated valves in Enbridge's responses mean remote operated valves commanded via SCADA at the direction of the control center operator.
2. When Line 9 is shut down it can be safely segment isolated by closure of remote operated valves along the pipeline system.
3. Maximum Volume Out release estimates between valves are affected not only by drainage, but by Enbridge's assumed time to shut down pumps and close the valves within 13 minutes. Such volumes are driven by the adequacy of the leak detection as well as control center operator proficiency to recognize a release and react appropriately.[16]

Failure to have a procedure, or follow a procedure of mainline segment isolation, significantly contributed to the release of oil in the Marshall, MI event, and raises questions as to the current adequacy of control room procedures and pipeline design to allow the control center to isolate a segment of a pipeline where there is a rupture, especially segments affecting high consequence areas. While I do not expect to uncover any surprises in the area of valving on Line 9, the NEB should follow through to their satisfaction on this subject given proper valve operation can play an important role after a pipeline rupture.

IV. Key Relevant Differences Between Canadian and U.S. Integrity Management Regulatory Approaches

Table 2 (U.S. and Canadian IM Liquid Pipeline Regulatory Approaches) on the following page, provides a simple summary of several major relevant differences in pipeline IM regulatory approaches between the U.S. and Canada. Table 2 is by no means meant to be an exhaustive list.

This section is not meant to be a complete comparison between U.S. and Canadian pipeline safety regulations, but rather an assessment of several major integrity management ("IM") approach differences that are significant as to how they impact the Project. Accufacts has observed that no particular country has developed a best regulatory pipeline safety practice, especially as it relates to IM to avoid rupture failure. Each country has certain approaches in

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[15] Accufacts Inc., "Accufacts' Perspective on Enbridge Filing for Modification on Line 9 Reversal Phase I Project," April 23, 2012, p. 10.

[16] Enbridge Response to Ontario Attachment 1 to Ontario IR 2.9.c, OH-002-2013 File OF-Fac-Oil-E101-2012-10 02.

specific areas that may be better or worse and different from those of other countries. It is eventually up to the citizens of each country to determine if the pipeline safety regulatory approaches are sufficient, especially given various differences in their jurisprudence systems. Accufacts feels very strongly, however, that the major purpose of any IM regulation is to assure a safety culture approach that is geared toward prudent management processes to avoid pipeline failures. It should be mentioned that all regulation, no matter how well intended, can be ineffective if the regulations are too complex, are not clear, or there is no appropriate follow-up or effective enforcement by the regulatory agencies whose resources are often stretched very thin.

Table 2 –U.S. and Canadian IM Liquid Pipeline Regulatory Approaches

IM Issue	Canada	U.S
Pressure Reduction	Permitted at discretion of operator without notification to regulator	Generally not permitted without prior notification to regulator
Minimum Assessment Intervals	Indicates continual assessment. Defines no minimum interval, reassessments determined by operator	Indicates continual assessment. Defines at least every 5 years not to exceed 68 months, restrictive variance permitted in limited situations
Defines Permitted Assessment Methods	No, but listed as examples	Yes
Identifies Certain At-risk Anomalies and Defines Remediation Timing to Address Them	No	Yes
Highly Dependent on Risk Approach	Yes, risk assessment very critical	Yes, risk based with focus on High Consequence Areas ("HCAs")
Engineering Assessments (EA)	Heavily dependent on EA defined and incorporated in regulation. Requires "conservative" assumption if data missing.	EA not defined in regulation, except in limited analysis situations.
Liquid Pipeline Application and IM Transparency	NEB application process for liquid pipelines more public and transparent. IM information can be sheltered from public, however.	Highly non public, even secretive, depending on specific state. Information controlled at discretion of the operator.

A key issue to an IM approach and its effectiveness is how public and transparent the core IM pipeline safety information is in order to assure the pipeline operator has their pipeline under reasonable control. The IM effort in the U.S. was initiated after several tragic liquid and gas transmission pipeline ruptures clearly demonstrated to the public that pipeline management had lost control of their pipelines for various reasons.[17] From my perspective, the Canadian NEB currently leads U.S. efforts in making much important pipeline and IM information public, though improvements are still warranted in this area in both countries.

V. Pipeline Integrity Assessment Technologies – Strengths and Weaknesses

As a result of high profile and tragic liquid and gas transmission pipeline ruptures, the Office of Pipeline Safety, the predecessor to the U.S. Pipeline and Hazardous Materials and Safety Administration ("PHMSA") responsible for pipeline safety in the U.S., in the early 2000's initiated federal pipeline safety rulemaking processes focused on requiring companies to phase in development of integrity management programs starting with liquid transmission pipelines. Prior to these rulemaking efforts, pipeline operators, under minimal federal pipeline safety regulations, were under no requirement to periodically reassess the integrity of their transmission pipelines except during the hydrotest following initial construction, though not all liquid pipelines were required to be hydrotested under various "grandfathering" exclusions.

The development of IM regulation required liquid pipeline transmission operators to initially baseline assess and periodically reassess their pipeline systems, depending on the type of threat, using four methods permitted in the IM regulations.[18] Canadian regulations also identify some of these methods as examples of pipeline inspection and testing but do not restrict assessment methods to those limited in U.S regulations.[19] Neither country identifies the various strengths and weaknesses of the assessment methods, but direct assessment as a process in the U.S. is clearly restricted to certain limited corrosion threats. Those methods defined in the U.S. pipeline regulations are summarized in Table 3 (Assessment Methods Identified in U.S. Pipeline IM Safety Regulations) with some of the various strengths and weaknesses I have observed in 40 years of experience in this area.

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[17] For example, NTSB/PAR-02/02 Pipeline Accident Report, " Pipeline Rupture and Subsequent Fire in Bellingham, Washington June 10, 1999," adopted October 8, 2002 and NTSB/PAR-03/01 Pipeline Accident Report, "Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000," adopted February 11, 2003.
[18] U.S. 49CFR§195.452(c) & (e).
[19] CSA Standards, "Oil and Gas pipeline systems – Z662-11, reprinted January 2012," Section 3.3.3.3, Notes (1) & (2), p. 33.

Table 3 - Assessment Methods Identified in U.S. Pipeline IM Safety Regulations

Assessment Method	Description	Strength	Weakness
Strength Testing (Usually hydrotest)	Takes critical axial aligned (e.g. cracks) anomalies to failure for properly designed hydrotest by applying a pressure safety margin. Claims of possible damage to pipe overplayed.	Proof test of system integrity establishing safety margin at time of test. Excellent at validating longitudinally oriented cracks, such as SCC. Canadian hydrotest regulation superior and more definitive than U.S. strength test regs.	Doesn't test girth welds well. Doesn't eliminate possible future crack threats, especially if test performed at too low a test pressure. Can leave anomalies in pipe that can grow to failure at a later date. Requires shutdown of pipeline.
Inline Inspection (ILI)	General Corrosion and Caliper (deformation/dent) ILI tools well developed from many decades of improvement and field verification. Crack tools still in early development with very mixed results.	When technology proven, tells more about condition of pipe than hydrotest. Pipeline usually doesn't have to be shut down.	Pipeline must be designed to run ILI tool. Good ILI results can still be misapplied. Running the ILI tool is usually the cheaper part of a pipeline assessment. Verification digs can cost more than ILI run. ILI technology claims often overstated.
Direct Assessment	Inferred process that uses direct readings of selected pipe sections usually via field digs.	Field dig observations usually more reliable for specific pipe segments observed.	Inferred assessment can leave much pipe not actually inspected. Can only be applied to certain corrosion risks.
Other Technology	Not defined, but open ended to permit development of new technologies if they can be demonstrated to work reliably to be equivalent (e.g. self propelled "robot" pigs with cameras, etc.)	Must be proven to satisfaction and approval of regulator before use allowed.	New technology doesn't always work as claimed. Important to understand its limitations.

VI. Central Findings in NTSB/PHMSA Investigation of Marshall, MI July 25, 2010 Rupture Applicable to Line 9

1) Accufacts synopsis of NTSB/PHMSA investigation

The following synopsis is gathered by Accufacts from information readily available in the public domain.[20] It should be noted that while the NTSB is ultimately responsible for their investigation and Final Report, many of the documents will indicate that PHMSA was also a party to many of the interviews.

On the afternoon of July 25, 2010 at approximately 5:58 PM (EDT) while shutting down the line for a temporary scheduled shutdown, Line 6B ruptured approximately 0.6 mile downstream from a mainline pump station at Marshall, MI (See Exhibit 4 - View of Line 6B ruptured pipe in trench). The pipe that ruptured was a 30-inch diameter, 0.25 inch thick, grade X-52, double submerged arc welded ("DSAW") pipe joint that failed at or below the maximum recorded discharge pressure at the closest upstream pump station, the Marshall Pump Station, of 486 psig (≤ 56% SMYS), which is well below the pipeline's MOP rating of 624 psig (72% SMYS).[21] The rupture failure occurred from an axial aligned crack that grew to a point of failure, such that the pipe ruptured below an Enbridge imposed pressure reduction of 523 psig (60% SMYS) at the time, and well below MOP.[22]

At the time of the rupture the pipeline was moving a unique form of oil called dilbit, a blend of Canadian tar sands oil diluted with a solvent, or diluent, to allow flow of the mixture at normal pipeline operating conditions established by pipeline tariffs, usually viscosity and gravity (density) limits. Through a series of misunderstandings, control center misoperations, and confusion caused by a perceived phenomena called column separation (aka slack line), where the pipeline does not operate liquid full, oil continued to spill from the pipeline over the next 17 plus hours as the pipeline segment containing the rupture remained not properly isolated and two subsequent lengthy startups (totaling approximately 1 ½ hours) were attempted. Emergency spill

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[20] 378 public files (as of 7/14/13) encompassing over 14,000 pages and almost 100 interviews are listed on the NTSB website for the July 25, 2010 Marshall, MI accident (DCA10MP007) located at:
http://dms.ntsb.gov/pubdms/search/hitlist.cfm?docketID=49814&CFID=23241&CFTOKEN=60045174

[21] MOP stands for Maximum Operating Pressure which is the normal maximum operating pressure permitted during normal operations on a particular pipeline segment established by regulations. MOP for liquid pipelines is usually a test qualification pressure divided by 1.25 (i.e., usually 72% SMYS in the U.S and up to 80% SMYS in Canada, though not always).

[22] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Material Laboratory Factual Report, Report No. 11-055," dated May 21, 2012, p. 2.

response procedures calling for shutdown and mainline valve isolation spanning the rupture site were not initiated until after a call was made to the control center from a non Enbridge utility company employee finding signs of spilled oil late in the morning of July 26, 2010. Enbridge estimated the 30-inch pipeline released 20,082 barrels (843,444 gallons). As of April 30, 2012, the EPA figures for recovered oil to that date had amounted to 27,334 bbls (1,148,012 gallons) substantially above Enbridge's earlier release estimate.[23] Given the propensity of dilbit to sink in water, oil recovery is still proceeding. As such, it is my understanding that a final estimate of the oil actually recovered has yet to be released. Current spill recovery costs have been estimated to exceed $1,000,000,000 U.S.

From an integrity management perspective, Enbridge relied on <u>one</u> highly specialized and what I would call push development technology "cracking tool" ILI (USCD) tool run in Line 6B in 2005. The objective of this specialized tool was to help detect axially aligned "anomalies" or crack features that can be very difficult to accurately determine and estimate time to failure. Axially aligned threats, such as SCC, are especially difficult to evaluate as these threats can occur in crack fields or clusters which is typical of SCC, or in combination with other threats such as corrosion-fatigue, that can make corrosion rates vary considerably. The 2005 USCD tool run was analyzed in early 2006 and results reported as capturing six crack-like (single crack) features in the pipe joint that ruptured at a site of SCC rather than the more significant crack colonies (i.e., crack-field). The NTSB reported "The crack feature corresponding to the rupture origin location was listed in the 2005 USCD report as a 51.6-inch-long crack-like feature with a maximum depth of 0.71 inches. In a post-accident analysis of the 2005 USCD data, PII found that the 51.6-inch long feature was misclassified as a crack-like feature in 2005."[24] Crack-like was defined to mean single crack while another term, crack-field, was used to indicate crack colonies or SCC. The rupture site was in an area of crack-field or SCC.

Enbridge's engineering assessments based on historical pressure cycling measurements and the 2005 USCD ILI run data placed Fitness for Service remaining fatigue life of the deepest crack feature in the pipe joint that eventually ruptured, at 21 years. This estimate was well beyond the approximate 4½ years to the actual rupture failure that occurred at much lower pressures than the engineering assessment calculated pressure thresholds.[25] In addition, underreporting by the ILI tool and analysis team resulted in the failure to identify this pipe joint for field dig verification to confirm ILI crack analysis that eventually caused the Line 6B "premature" rupture failure.

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[23] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Enbridge Line 6B Addendum to Emergency and Environmental Response Group Chairman's Factual Report," dated June 13, 2012, p. 2.

[24] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study Report No. 12-046," April 20, 2012, p. 2.

[25] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Material Laboratory Factual Report – Report No. 11-055," May 21, 2012, pp. 21 - 23 and Figure 27, p. 42.

Enbridge was in the process of running another crack detection tool in 2010 when the pipeline ruptured.

Surprisingly, exacerbating the IM crack analysis of Line 6B, was:

1. GE's misreporting / mischaracterization of the SCC crack field anomalies in the pipe joint,
2. Enbridge's failure to use the proper nominal wall thicknesses for the pipe joint reported by previous ILI tools designed for such wall thickness measurements (the USCD tool was not designed for such measurements as its focus was crack feature identification),
3. Enbridge's failure to utilize remaining wall thickness measurements at the crack colonies (e.g., failing to integrate integrity data from various ILI runs), and
4. Enbridge's failure to incorporate crack tool tolerances that should assist in accounting for ILI tool imprecision.

The SCC that failed was in an area of general corrosion wall loss that further reduced the remaining pipe thickness in the area of crack penetration (See Exhibit 5 - Line 6B rupture site actual pipe crack penetration/corrosion wall loss). Clearly, this developing crack feature technology ILI run was still in development and limited or biased, definitely understating at least the depth and the seriousness of crack anomalies, which was the very intent of the USCD ILI tool run. Compounding the problems with this ILI tool's use, was Enbridge's failure to incorporate additional data, such as information from various different ILI runs actually designed to measure wall thickness (the USCD tool was not designed to measure pipewall thickness). A core requirement of IM processes, and associated risk management applications and pipeline safety regulations is the integration of data to assure the integrity of the pipe.

Based on the short time to rupture failure, Enbridge's subsequent engineering assessment approaches on Line 6B based on this ILI technology were highly incomplete and far from "conservative." The NTSB estimated average annual crack growth rate determined from the December, 2005 crack ILI run to the July 25, 2010 rupture at the crack failure to be 0.574 millimeters per year compared to Enbridge's assumed maximum growth rate on Line 6B of 0.38 millimeters per year.[26] This NTSB observation differs considerably from the response by Enbridge to an Information Request in the NEB Application process regarding crack growth rates on Line 6B for the pipe that ruptured.[27] Enbridge's maximum crack growth rates were too low, by approximately 50% for the site that ruptured, as compared to the NTSB estimated average annual crack growth rate. SCC, especially for sites where corrosion fatigue and/or general corrosion may

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[26] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study, Report No. 12-046," 4-20-12, p. 6.

[27] Enbridge Response to Equiterre Information Request No. 1.1.(s), p.4, "There was no yearly growth rate specified by the NTSB for Line 6B."

be present, can exhibit a wide range of growth rates that can vary, depending on the corrosion environment and the pressure cycle/fatigue stress spectrum that can cause the crack colonies to link as well as grow unpredictably. SCC crack growth rates can be off by an additional margin if such SCC is occurring in sites of general corrosion wall loss due to the interaction of the threats on each other to accelerate growths. SCC predicted time to failure based on crack ILI and engineering assessments still remain a significant challenge.

2) NTSB investigation of Line 6B July 25, 2010 Marshall, MI rupture

After a detailed investigation, the National Transportation Safety Board ("NTSB") determined that 28 Findings were relevant to the July 25, 2010 Line 6B incident. Given their related applications to the proposed Line 9 Project, the NTSB Findings are summarized below as taken directly from the NTSB Accident Report for the Marshall, MI rupture event.[28] While all the NTSB Findings are significant their Findings related to IM are specifically called to mind as Nos. 3, 4, 5, 6, 7, 8, 9, 10, 27, and 28 are directly associated with IM issues that may apply to the Line 9 Project. I have extracted the NTSB Findings and bolded those IM related findings for easy reference.

a) NTSB Findings

1. The following were not factors in this accident: cathodic protection, microbial corrosion, internal corrosion, transportation-induced metal fatigue, third-party damage, and pipe manufacturing defects.

2. Insufficient information was available from the postaccident alcohol testing; however, the postaccident drug testing showed that use of illegal drugs was not a factor in the accident.

3. **The Line 6B segment ruptured under normal operating pressure due to corrosion fatigue cracks that grew and coalesced from multiple stress corrosion cracks, which had initiated in areas of external corrosion beneath the disbonded polyethylene tape coating.**

4. **Title 49 *Code of Federal Regulations* (CFR) 195.452(h) does not provide clear requirements regarding when to repair and when to remediate pipeline defects and inadequately defines the requirements for assessing the effect on pipeline integrity when either crack defects or cracks and corrosion are simultaneously present in the pipeline.**

5. **The Pipeline and Hazardous Materials Safety Administration (PHMSA) failed**

[28] NTSB Accident Report "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release Marshall, Michigan July 25, 2010," NTSB/PAR-12-01, adopted July 10, 2012, pp. 118 - 120.

to pursue findings from previous inspections and did not require Enbridge Incorporated (Enbridge) to excavate pipe segments with injurious crack defects.

6. **Enbridge's delayed reporting of the "discovery of condition" by more than 460 days indicates that Enbridge's interpretation of the current regulation delayed the repair of the pipeline.**

7. **Enbridge's integrity management program was inadequate because it did not consider the following: a sufficient margin of safety, appropriate wall thickness, tool tolerances, use of a continuous reassessment approach to incorporate lessons learned, the effects of corrosion on crack depth sizing, and accelerated crack growth rates due to corrosion fatigue on corroded pipe with a failed coating.**

8. **To improve pipeline safety, a uniform and systematic approach in evaluating data for various types of in-line inspection tools is necessary to determine the effect of the interaction of various threats to a pipeline.**

9. **Pipeline operators should not wait until PHMSA promulgates revisions to 49 CFR 195.452 before taking action to improve pipeline safety.**

10. **PII Pipeline Solutions' analysis of the 2005 in-line inspection data for the Line 6B segment that ruptured mischaracterized crack defects, which resulted in Enbridge not evaluating them as crack-field defects.**

11. The ineffective performance of control center staff led them to misinterpret the rupture as a column separation, which led them to attempt two subsequent startups of the line.

12. Enbridge failed to train control center staff in team performance, thereby inadequately preparing the control center staff to perform effectively as a team when effective team performance was most needed.

13. Enbridge failed to ensure that all control center staff had adequate knowledge, skills, and abilities to recognize and address pipeline leaks, and their limited exposure to meaningful leak recognition training diminished their ability to correctly identify the cause of the Material Balance System (MBS) alarms.

14. The Enbridge control center and MBS procedures for leak detection alarms and identification did not fully address the potential for leaks during shutdown and startup, and Enbridge management did not prohibit control center staff from using unapproved procedures.

15. Enbridge's control center staff placed a greater emphasis on the MBS analyst's flawed interpretation of the leak detection system's alarms than it did on reliable indications of a leak, such as zero pressure, despite known limitations of the leak detection system.

16. Enbridge control center staff misinterpreted the absence of external notifications as evidence that Line 6B had not ruptured.

17. Although Enbridge had procedures that required a pipeline shutdown after 10 minutes of uncertain operational status, Enbridge control center staff had developed a culture that accepted not adhering to the procedures.

18. Enbridge's review of its public awareness program was ineffective in identifying and correcting deficiencies.

19. Had Enbridge operated an effective public awareness program, local emergency response agencies would have been better prepared to respond to early indications of the rupture and may have been able to locate the crude oil and notify Enbridge before control center staff tried to start the line.

20. Had the firefighters discovered the ruptured segment of Line 6B and called Enbridge, the two startups of the pipeline might not have occurred and the additional volume might not have been pumped.

21. Although Enbridge quickly isolated the ruptured segment of Line 6B after receiving a telephone call about the release, Enbridge's emergency response actions during the initial hours following the release were not sufficiently focused on source control and demonstrated a lack of awareness and training in the use of effective containment methods.

22. Had Enbridge implemented effective oil containment measures for fast-flowing waters, the amount of oil that reached Talmadge Creek and the Kalamazoo River could have been reduced.

23. PHMSA's regulatory requirements for response capability planning do not ensure a high level of preparedness equivalent to the more stringent requirements of the U.S. Coast Guard and the U.S. Environmental Protection Agency.

24. Without specific Federal spill response preparedness standards, pipeline operators do not have response planning guidance for a worst-case discharge.

25. The Enbridge facility response plan did not identify and ensure sufficient resources were available for the response to the pipeline release in this accident.

26. If PHMSA had dedicated the resources necessary and conducted a thorough review of the Enbridge facility response plan, it would have disapproved the plan because it did not adequately provide for response to a worst-case discharge.

27. **Enbridge's failure to exercise effective oversight of pipeline integrity and control center operations, implement an effective public awareness program, and implement an adequate postaccident response were organizational failures that**

resulted in the accident and increased its severity.

28. **Pipeline safety would be enhanced if pipeline companies implemented safety management systems.**

b) NTSB Recommendations to Enbridge following the Marshall rupture

The NTSB made numerous recommendations following their investigation of the Marshall, MI incident. Of special concern are the recommendations made to Enbridge (aka Enbridge Incorporated):

> "Revise your integrity management program to ensure the integrity of your hazardous liquid pipelines as follows: (1) implement, as part of the excavation selection process, a safety margin that conservatively takes into account the uncertainties associated with the sizing of crack defects from in-line inspection; (2) implement procedures that apply a continuous reassessment approach to immediately incorporate any new relevant information as it becomes available and reevaluate the integrity of all pipelines within the program; (3) develop and implement a methodology that includes local corrosion wall loss in addition to the crack depth when performing engineering assessments of crack defects coincident with areas of corrosion; and (4) develop and implement a corrosion fatigue model for pipelines under cyclic loading that estimates growth rates for cracks that coincide with areas of corrosion when determining reinspection intervals. (P-12-11)
>
> Establish a program to train control center staff as teams, semiannually, in the recognition of and response to emergency and unexpected conditions that includes supervisory control and data acquisition system indications and Material Balance System software. (P-12-12)
>
> Incorporate changes to your leak detection processes to ensure that accurate leak detection coverage is maintained during transient operations, including pipeline shutdown, pipeline startup, and column separation. (P-12-13)
>
> Provide additional training to first responders to ensure that they (1) are aware of the best response practices and the potential consequences of oil releases and (2) receive practical training in the use of appropriate oil-containment and -recovery methods for all potential environmental conditions in the response zones. (P-12-14)
>
> Review and update your oil pipeline emergency response procedures and equipment resources to ensure that appropriate containment equipment and methods are available to respond to all environments and at all locations along the pipeline to minimize the spread of oil from a pipeline rupture. (P-12-15)

Update your facility response plan to identify adequate resources to respond to and mitigate a worst-case discharge for all weather conditions and for all your pipeline locations before the required resubmittal in 2015. (P-12-16)"[29]

c) Enbridge's responses to NTSB IM concerns

Accufacts has reviewed Enbridge's responses to Ontario-specific requests related to their Application process for the Line 9B Project, and various Enbridge Responses to the NTSB/PHMSA during the NTSB Marshall, MI rupture investigation at MP 608 on Line 6B.[30, 31, 32] Concerning the NTSB IM recommendations, it should become fairly clear from comparing the referenced documents that Enbridge has failed to incorporate important NTSB recommendations into their integrity management program and this Project's EA, especially as they relate to the unique and highly challenging threats related to prevalent SCC and associated corrosion, and corrosion fatigue along Line 9. Line 9 contains numerous similar threats associated with polyethylene external coating disbondment and the Enbridge EA fails to adequately demonstrate a prudent evaluation of the SCC /corrosion threat risks on Line 9.

I further find that Enbridge's approach to cracking threat assessment via ILI as provided in the Section 4 of the Project's EA has not included many of the NTSB recommendations. I see no sufficient detail in the EA that the Enbridge approach has incorporated information to assure that still-developing crack detection ILI technology is being applied in such a manner so as to recognize that this ILI method is still "push technology" and is not reliable, especially when it comes to SCC in corrosion sites associated with this polyethylene tape coating. I use the term "push technology" to mean the application of a new still developing technological approach *that has yet to be sufficiently field demonstrated to be highly accurate or reliable, either by the use of the ILI tool or related engineering assessments using the tool's results.*

The EA also fails to mention that the 2004/2005/2006 crack runs may be of questionable value based on the Marshall, MI rupture. As a matter of reference, the crack in the Marshall, MI pipeline utilized the same ILI tool crack technology, the same biased software algorithm

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[29] *Ibid.,* pp. 123 -124.

[30] Line 9B Reversal and Line 9 Capacity Expansion Project OH-002-2013 File-OF-Fac-Oil-E101-2012-10 02, Enbridge Response to Ontario Ministry of Energy ("Ontario") Information Request No. 1., Section 1.44 Michigan and other Spills, pp. 70 – 77.

[31] Enbridge submission to NTSB, "Enbridge Energy, Limited Partnership Party Submission Investigation of July 2010 Line 6B Accident Near Marshall, Michigan; NTSB ID: DCA 10MP007," May 22, 2012.

[32] Enbridge response to NTSB email request of April 3, 2012 by Matt Nicholson during MP 608 – Marshall Michigan Incident NTSB/PHMSA Information Request Number 404, "Enbridge Responses to NTSB/PHMSA No. 404," pp. 1 – 15.

underreporting SCC depths, and that missed the rupture site on Line 6B that occurred well below MOP. The use of this ILI tool should thus be characterized as *still in development*, a research experiment. I see no specific indication in the crack section of the Project's EA that Enbridge has embraced or appropriately incorporated the IM recommendations of the NTSB for the 2004/2005/2006 crack ILI tool runs, and the EA was submitted to the NEB well after the NTSB report on Marshall was adopted.

VII. Summary of PHMSA Violations on Marshall, MI Failure

On September 7, 2012 following an investigation of the Marshall event and probable violation notice due process, PHMSA, the federal agency charged with pipeline safety in the U.S., issued to Enbridge Energy a Final Order. The Final Order rendered 24 items of violation of U.S federal minimum pipeline safety regulations involving the Marshall, MI incident, assessing a civil penalty of approximately $3.7 million. Four of the 24 violations I would also characterize as violations of the integrity management section of the minimum federal safety regulations. Two of the four IM violations (items 1 and 4 below) were assessed the maximum fine permitted under law of $1,000,000 underscoring the gravity of the IM violations.[33] While the Line 9 Project is governed by Canadian pipeline safety regulations, given the importance that the PHMSA findings of violations may play in any IM safety process, I have indicated the IM violations below. The reader should find that there are several critical IM violations that might relate to IM approaches in Canada as well, and a review of Section IV will suggest some findings that may not be considered a violation in Canada. Extracting directly from the PHMSA Final Order:[34]

1) §195.452 Pipeline integrity management in high consequence areas.

(h) ***What actions must an operator take to address integrity issues?***

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ....

(2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that

[33] Under the 2011 Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, the maximum civil fine that PHMSA can levy for a related series of violations has now been raised to $2,000,000.

[34] PHMSA, "Final Order, CPF 3-2012-5013," dated September 7, 2012.

determination, unless the operator can demonstrate that the 180-day period is impracticable.

Enbridge failed within 180 days after an integrity assessment of Line 6B to obtain sufficient information about anomalous conditions presenting a potential threat to the integrity of Line 6B. Enbridge conducted a high-resolution MFL integrity assessment of Line 6B on October 13, 2007. Enbridge received a vendor report on June 4, 2008 regarding this ILI run. The 180 day deadline was April 10, 2008. Enbridge did not demonstrate that the 180 day period was impracticable.

Enbridge implemented pressure restrictions as of July 17, 2009, a period of approximately 462 days after the deadline to have sufficient information to identify anomalous conditions. After another year, on July 15, 2010, the company submitted a Long Term Pressure Reduction Notification to PHMSA on July 15, 2010 in which the date of discovery was reported by Enbridge as July 17, 2009.

2) §195.452 Pipeline integrity management in high consequence areas.

(i) What actions must an operator take to address integrity issues?

(4) Special requirements for scheduling remediation

Beginning with the 2004 USWM ILI, Enbridge did not schedule remediation of corrosion anomalies involving the longitudinal weld seam of pipe joint #217720 within 180 days of discovery of the conditions as required by **§195.452(h)(4)(iii)(H).** Enbridge also did not remediate crack-like anomalies on the same pipe joint (longitudinal in orientation) that could impair the integrity of the pipeline reported by the 2005 USCD ILI as required by **§195.452(h)(4)(iv)** in accordance with **(Appendix C)(VIl)(D).** Enbridge could not demonstrate that the company attempted or scheduled any remediation of the corrosion or crack anomalies that were identified by the assessments.

The reported corrosion and crack like anomalies on pipe joint #217720, on Line 6B, were not selected for excavation, and the pipe joint ultimately ruptured in service on July 25, 2010, resulting in a crude oil release of over 20,000 bbls, and significant environmental damage, as the released product migrated to a creek, which in turn flowed into the Kalamazoo River.

3) §195.452 Pipeline integrity management in high consequence areas.

(i) What preventive and mitigative measures must an operator take to protect the high consequence area?

(1) General requirements. An operator must take measures to prevent

and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures included conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection .

(2) Risk analysis criteria. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
(ii) Elevation profile;
(iii) Characteristics of the product transported;
(iv) Amount of product that could be released;

In preparing the risk analysis, Enbridge failed to consider all relevant risk factors associated with the determination of the amount of product that could be released from a rupture on Line 6B. Enbridge's risk analysis process assumed a pipeline rupture of this magnitude would be identified by instrumentation (SCADA and Leak Detection System) within 5 minutes, and that it would take an additional 3 minutes to close remotely operated valves on either side of the rupture. The amount of product that could be released is clearly impacted by different operating scenarios including transient conditions such as those associated with start-ups and shutdowns or personnel response to abnormal operating conditions.

Prior to the release, Enbridge estimated the worst case scenario release at the M.P. 608 location to be 1,670 bbls initial volume out, plus 1938 bbls stabilization loss (drain down) for a total of 3,608 bbls.

The actual failure scenario demonstrates the rupture was not recognized by Enbridge, and the isolation valves were not closed, until approximately 17 hours after it occurred. An additional 16,431 bbls of product was injected into the ruptured pipeline, causing the total spill volume to greatly exceed Enbridge's worst case discharge scenario for this location.

4) §195.452 Pipeline integrity management in high consequence areas.

(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(2) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline,

> including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

Enbridge did not properly consider the results of corrosion and cracking assessments nor did Enbridge integrate the information from these assessments to properly assure overall pipeline integrity. Witness interviews and prior ILI assessment results of Line 6B, including 2004 USWM, 2005 USCD, 2007 MFL, and 2009 USWM demonstrate that Enbridge has a long history of performing integrity assessments using ILI tools. These assessment results were evaluated independently and not integrated in a fashion that assures pipeline integrity.

Additional observations are very relevant as it relates to the Enbridge incomplete and deficient IM program, their recurring pattern of failing to prudently and effectively incorporate regulator IM audit findings related to these serious deficiencies, and how these serious process failings led to the Marshall, MI rupture failure. For example, SCC is obviously a cracking threat by its nature, but is also a corrosion threat though most conventional general corrosion inline inspection tools are incapable of reliably identifying this highly selective form of corrosion/cracking threat that tends to fail more as cracks. Thus, for potential ILI evaluation, SCC and other more selective forms of corrosion tend to fall into the specialized much more difficult form of "crack feature" detection ILI tools. As discussed later in this report, such ILI crack detection tools are fairly new in their technical development and field application. These tools have serious technical limitations as to their accuracy and reliability (what I call push technologies), and it is hoped technical improvements and advancements will eventually occur. Until then pipeline operators need to incorporate various safety margins commensurate with the field advancement or lack of advancement of a particular ILI inspection tool for its intended design. Such safety factors include incorporating the tool tolerance and clear presentation of unity plots (both depth and length) to uncover ILI tool bias, especially if a developing tool is indicating in the non-conservative range, such as understating crack depth and length, as well as characterization.

VIII. Accufacts Conclusions and Recommendations to NEB

The following are my conclusions and recommendations based on a review of the Project's documents include IR responses.

A) Conclusions

1) SCC within corrosion wall loss is prevalent and a high risk along Line 9

The EA makes it fairly clear that a primary IM threat prevalent along Line 9 is cracking introduced by the polyethylene disbonded coating tenting in close proximity to the DSAW seam weld.[35] This disbonded coating has permitted significant SCC to occur within general wall loss corrosion in or near the DSAW seam. A CP system is ineffective in dealing with this type of coating disbondment and will not protect against this SCC/corrosion threat, as the protective CP current cannot get to the affected pipe steel that is shielded by this type of coating. SCC by itself in pipelines is somewhat difficult to access but when such SCC is coincident with corrosion wall loss, the engineering assessments can be very difficult to perform with a high degree of confidence and accuracy. It should be obvious that Fitness for Service or engineering assessments must actually consider the real remaining wall thickness as well as other factors. Phased array ultrasonic crack detection ILI tools attempt to measure crack depth, and this technical approach does not accurately measure pipe wall thickness. The phased array crack detection tools must be supplemented or ILI trains combined with other wall thickness measure ILI tools that are designed to actually measure wall thickness, but don't measure cracks.

While it is true that current industry standards have not been developed to address this serious interactive threat combination, the prevalence of such interactive threats on Line 9 does not excuse Enbridge from running the right tools or integrating various tools, or exceeding industry standards, or choosing other assessment methods such as hydrotesting, to assess pipeline integrity for service.[36] In the Marshall, MI rupture the NTSB made it very clear that Enbridge's IM approach failed to coordinate SCC within corrosion wall loss sites (See Exhibit 3 – Table of remaining strength calculations for 51.6 inch long feature that ruptured in Marshall MI using various wall thicknesses and ILI tool tolerances) among other engineering assessment failings. Enbridge has not incorporated such a serious NTSB recommendation into the Line 9B Project's IM approach. This observation is further supported by Enbridge's recent response to Ontario's IR that fails to identify such a critical detail as integrating interactive threats (cracking and corrosion) that seriously contributed to the Marshall rupture.[37]

In addition, the Line 9B Project's EA also fails to make a key point very clear, that the ILI tool during 2004/2005/2006 was non conservative (understated crack depths) for SCC so it is not clear if the EA submitted results have been correctly adjusted for this well-know tool bias, known both to the pig vendor GE and Enbridge, in those specific tool runs. This was the same problem in the 2005 Marshall, MI crack tool run that failed to properly classify and correct for that tool run's non-conservative bias. Such under indicating can seriously taint Fitness for Service or engineering assessment approaches. This is a recurring problem within Enbridge that

[35] Enbridge Pipelines Inc. Pipeline Integrity Department, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment," Submitted to National Energy Board, November 2012, pp. 57 - 59.
[36] Enbridge submission to NTSB, "Enbridge Energy, Limited Partnership Party Submission Investigation of July 2010 Line 6B Accident Near Marshall, Michigan; NTSB ID: DCA 10MP007," May 22, 2012, pp. 11 -12.
[37] Enbridge Response to Ontario IR 1.44.a., p 71.

has been discovered by Canadian and U.S. investigators after other pipeline crack ruptures (See on the next page, Table 4 - Recent Enbridge Pipeline Ruptures After Crack ILI).[38]

2) The ILI cracking tool appears to still be a research experiment

Given various information uncovered by the NTSB Marshall investigation, it is evident that the pig vendor and Enbridge knew that there were non conservative biases introduced by the crack detection ILI tool. The ability of the crack detection tool to reliably identify SCC was overstated. Enbridge's engineering assessments' inability to apply proper tool tolerance for such developing technology as well as the failure to properly integrate such information with other threats, leads me to conclude that the ILI crack tool runs are more along the line of a research experiment with a high potential for error. Enbridge appears overfocused on running ILI technology when such special applications may not be reliable to assure a pipeline's integrity. These ILI runs are the cheaper part of an ILI assessment approach, and such developing tools need a increasing amount of verification digs to assure the newer technology is actually working in the field as claimed. In addition, even if the ILI tool is performing correctly the pipeline operator must incorporate engineering assessments that actually allow a rational time-to-failure estimate of cracks to assure they don't fail in service.

Table 4 – Recent Enbridge Pipeline Ruptures After Crack ILI

Date	Line #	Diameter (inch)	Estimated Release (BBls)	Location
7/4/02	3	34	~ 6,000	Cohasset, MN
4/15/07	3	34	~ 6,214	Glenavon, SK
11/13/07	3	34	Not available	Clearbrook, MN
1/8/10	2	26	3,784	Neche, ND
4/17/10	2	26	Not available	Deer River, MN
7/25/10	6B	30	+20,000	Marshall, MI
7/27/12	14	24	~1,200	Grand Marshall, WI

As demonstrated in Table 4, clearly there is still much work needed before ILI crack technology and engineering assessments can be considered reliable, especially on SCC. While I support the development of ILI technology and advancements, crack ILI and their application concerning engineering assessments are still a research experiment when it comes to the serious SCC evaluation challenges especially in sites within pervasive corrosion.

It is true that a properly developed, field demonstrated, and utilized ILI tool, usually designed for a specific purpose, can tell one more about a pipeline than a hydrotest, for example. Such more reliable and proven ILI approaches, however, have evolved and advanced over many decades. The level of ILI crack detection evolving in the last decade has not yet reached the reliability of

[38] NTSB, "Liquid Pipeline Accident – Marshall, Michigan Integrity Management Group Chair's Factual Report," pp. 21 – 26.

hydrotesting, especially for SCC and/or other crack features such as fatigue cracks. The obligation to choose, use, and apply the right assessment method(s) falls to the pipeline operator who eventually must demonstrate their use is appropriate. If an ILI tool cannot prove reliable and accurate, or its results used appropriately, hydrotesting is still a superior assessment method for many types of threats, especially axially aligned crack threats. As in all assessment methods, periodic reassessments are needed depending on the threat, even for hydrotesting.
Industry standards also require the pipeline operator to verify pig vendor assertions and claims for very good reasons.[39] The pipeline operator is responsible for the safe operation of their pipeline. In selecting IM assessment methods the operator must incorporate each assessment method's strengths, weaknesses, and capabilities to address certain threats. Since Enbridge has only recently incorporated changes in the ILI crack tools that were well known by the ILI vendor and Enbridge since 2008 to adjust for SCC misclassification and non-conservative depth bias, I cannot determine if the USCD ILI tool runs of 2012 will be accurate or reliable, or if field verification digs are appropriate for this still developing "push technology."[40]

3) Changing crude slates, especially dilbit, will substantially increase crack growth rates

There are numerous SCC crack threats along Line 9B and these threats are highly susceptible, given their axial orientation, to operating pressure cycling such as those associated with changes in a wide range of crudes that are being proposed for the reversal project. The movement of dilbit, given the substantial changes associated with small variation in composition either in the bitumen or the diluent solvent while meeting tariff requirements, merit exceptional attention on pipelines posing such cracking risks.

Enbridge needs to assure that their crack growth rates ("CrGRs") are truly conservative. Such CrGRs can vary substantially when they involve SCC / fatigue corrosion, especially with major changes in crude makeup. Once a pipeline operator has established the ability of an ILI tool to reliably identify a threat of concern, such as cracking, estimated crack growth rates need to be demonstrated to be truly conservative in determining the next crack tool reassessment. Exhibit 7 (Enbridge estimated corrosion growth rates) is an Enbridge response to a question concerning corrosion growth rates (CGRs).[41] These Enbridge reported numbers are substantially lower than the NTSB estimated average annual crack growth rate for the Marshall, MI rupture determined from the December, 2005 crack ILI run to the July 25, 2010 rupture at the SCC/corrosion failure of 0.574 millimeters per year.[42, 43] Granted, the estimated NTSB growth rates include both

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[39] API, "API Recommended Practice 1163 In-line Inspection Systems Qualification Standard," first edition August 2005, updated April, 2013.
[40] NTSB, "12-9-11 Interview of Clint Garth, Global Analysis Manager for Ultrasonics of GE PII Pipeline Solutions and Geoff Foreman, Growth and Structure Leader for GE PII Pipeline Solutions," p. 14.
[41] Enbridge Response to Les Citoyens au Courant, Attachment 1 to Les Citoyens au Courant IR Question 5.11.b, OH-002-2013 File OF-Fac-Oil-E101-2012-10 02.
[42] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Materials Laboratory Study for the Marshall, MI Report No. 12-046," 4-20-12, p. 6.
[43] Enbridge Response to Equiterre IR No. 1.1.s & 1.1.t, OH-002-2013 File OF-Fac-Oil-E101-2012-10 02, p. 4.

corrosion and crack growth which is the more relevant crack growth rate approach for this type of crack threat.

4) Line 9B is situated in significant high consequence areas

A detailed review of the maps provided in the NEB process of Line 9B and Responses to Equiterre IRs will readily demonstrate that a great deal of Line 9 is located near large populations and/or sensitive waterways/wetland areas where a rupture will have serious consequences.[44, 45] This is not a pipeline routed in sparsely populated non sensitive areas of Canada, but a pipeline running in some of the more populated corridors of southeastern Canada. Such a route definitely merits special considerations in IM approaches that actually reflect true conservativeness.

5) SCC cracks are most likely to fail as rupture

There is a long history in both Canada and the U.S. demonstrating that SCC, when it goes to failure, will usually fail as rupture, which is one reason why SCC threats command much respect. The EA has not adequately demonstrated that the ILI tool and related engineering assessments have reached the level of confidence that such massive and pervasive SCC threats on Line 9 can be remediated before they reach rupture limits.

6) Enbridge has failed to heed some important IM recommendations of the NTSB following the Marshall rupture

Regarding Enbridge's IM program following the Marshall, MI incident, the NTSB identified Enbridge's IM program as inadequate because it did not consider the following:

I. a sufficient margin of safety,
II. appropriate wall thickness,
III. tool tolerances,
IV. use of a continuous reassessment approach to incorporate lessons learned,
V. the effects of corrosion on crack depth sizing, and
VI. accelerated crack growth rates due to corrosion fatigue on corroded pipe with a failed coating.[46]

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[44] NEB, "Line 9B Stantec Scale Maps Showing pump stations, existing valves MP, KP and other sensitive environments highlighted in color," Files:
A316Z3_-_03_Attachment_1_to_NEB_2.7_pages_1_to_60.pdf,
A316Z3_-_03_Attachment_1_to_NEB_2.7_pages_61_to_120.pdf,
A316Z3_-_03_Attachment_1_to_NEB_2.7_pages_121_to_175.pdf.
[45] Enbridge Response Attachment 1 to Equiterre IR 1.3a and b, "Segments of pipeline in Highly Populated Areas (HPA), Other Populated Areas (OPA), Environmentally Sensitive Areas (ESA), Drinking Water Sources (DW) and Commercially Navigable Waterways (CNW)."
[46] NTSB Accident Report "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release Marshall, Michigan July 25, 2010," NTSB/PAR-12-01, adopted July 10, 2012, p.118.

7) Something appears very wrong with Enbridge's Line 9B risk assessment

A review of Exhibit 6 (Enbridge's Risk Profile for Line 9B (NW – ML) Pre and Post Flow Reversal) taken from their engineering assessment should be raising all sorts of questions and challenges.[47] I would advise the NEB to further explore the impression given by the EA that there is very little change in the risks from the reversal. Accufacts finds particularly disturbing the statement, "Based on this EA, there are presently no features reported by the 2004, 2005 and 2006 crack detection inspections that are predicted to reach critical dimensions until December 2013 based on current reduced operating pressures."[48] The impression that is being created is that engineering assessment predictions can be reliably estimated for cracks within one year. I must assume that this calculation has not included the NTSB findings and recommendations that clearly indicated that such Enbridge calls needed true "conservativeness." There is just too much uncertainty with cracks coinciding with corrosion to convey such time-to-failure accuracy, especially if an accurate remaining wall thickness is not utilized. Enbridge has also still failed to incorporate the interactive threats associated with corrosion and cracking with real conservatism, such as using a safety factor as recommended by the NTSB.[49]

8) Enbridge's culture of implied hydrotesting safety margins appears to be an illusion – the most dangerous of safeties

Enbridge's continued use of the hydrotesting pressure value (usually 1.25 of MOP) as a threshold safety margin is conveying a margin of safety that in all probability does not exist, creating the worst of all safeties, an illusion of safety.

Line 9B was last hydrotested in 1997 to a pressure level that established MOP. Enbridge did not answer Equiterre's request about hydrotest pressure as a percent of SMYS, an important IM assessment parameter.[50] As noted by the NTSB, the thresholds utilized by Enbridge to determine verification field digs for corrosion and cracking ILI calls, did not apply the same level of safety margin between corrosion (RPR=1 is 100% SMYS) and cracking (hydrotesting threshold is usually, but not always, 90% SMYS).[51, 52, 53] The safety factors for general corrosion have stood

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[47] Enbridge, "Line 9B Reversal and Line 9 Capacity Expansion Project Pipeline Integrity Engineering Assessment, Figure 4.47 Risk Profile for Line 9B (NW-ML) Pre and Post Flow Reversal," November 2012, p. 82.
[48] *Ibid.,* p. 82.
[49] Enbridge submission to NTSB, "Enbridge Energy, Limited Partnership Party Submission Investigation of July 2010 Line 6B Accident Near Marshall, Michigan; NTSB ID: DCA 10MP007," May 22, 2012.
[50] Line 9B Reversal and Line 9 Capacity Expansion Project OH-002-2013 File-OF-Fac-Oil-E101-2012-10 02, Equiterre Information Request No 1.1d, p. 3, and Enbridge Response to Ontario Information Request No. 1.14.a, Hydrostatic Test, p. 22 - 23.
[51] American Society of Mechanical Engineers ("ASME"), "Manual for Determining the Remaining Strength of Corroded Pipes: Supplement to B31 Code for Pressure Piping – B31G-2012," 2012 edition.
[52] CSA Standards, "Oil and Gas pipeline systems – Z662-11, reprinted January 2012," Section 3.3.3.3, Notes (1) & (2), p. 177.

the test of many decades of verification while crack failure predictions are a more recent development, especially for SCC/corrosion-fatigue/corrosion. Ironically, the most difficult to determine category of threats, with the least likely predictability for time-to-failure, cracking features have the lower threshold safety margin in Enbridge's IM program.

9) Given the many deficiencies uncovered in this application Accufacts places Line 9 at a high risk of rupture failure post reversal

Given the following:

I. the preponderance of new information surprisingly uncovered in the NTSB investigation and the associated Enbridge interviews;
II. Enbridge's failure to incorporate the NTSB IM recommendations,
III. the apparent disconnect in the Risk Assessment in the EA,
IV. the continual apparent refusal of Enbridge to prudently integrate SCC cracking threats with corrosion wall loss,
V. the difficulty in evaluating extensive SCC across the system,
VI. the still-in-development (research project) nature of the ILI crack tool, and
VII. Accufacts' extensive pipeline experience, including IM regulatory development and investigative experience,

I must conclude there is a high risk that Line 9 will rupture from the SCC/corrosion-fatigue/general corrosion interaction attack in the early years following Project implementation: and that Enbridge's IM approach, which relies on ILI and related engineering assessments, will not prevent rupture <u>under the operating conditions</u> resulting from the implementation of the Project.

10) Enbridge's leak detection will not timely detect rupture

The NTSB recommended that leak detection "Incorporate changes to your leak detection processes to ensure that accurate leak detection coverage is maintained during transient operations, including pipeline shutdown, pipeline startup, and column separation. (P-12-13)"[54] Additional NTSB factual reports during the Marshall investigation indicate that Enbridge has a culture of column separation which significantly complicates the reliability of leak detection in the control room to avoid false alarms. Enbridge has reported that the MBS systems across their pipeline network were requiring the MBS analysts in the control room to receive an average of 1.7 to 4.5 MBS alarms during a normal 12-hour shift in the first seven months of 2010.[55] This is a very high number of false leak alarms in a shift. While it is not illegal to operate in column

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[53] U.S. pipeline regulation 49CFR§195.304 **Test Pressure**.

[54] NTSB Accident Report "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release Marshall, Michigan July 25, 2010," NTSB/PAR-12-01, adopted July 10, 2012, p. 123.

[55] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Liquid Pipeline Accident – Marshall, Michigan, Group Chairman's Factual Report Human Factors," dated March 28, 2012, p. 25.

separation (aka slack line), where the pipeline is not liquid full, industry standards warn about the complication in reliability of such leak detection systems. Column separation can seriously hinder and delay control center recognition of possible rupture indications as was clearly the case in the Marshall, MI rupture involving a release of over 17 hours.

11) Rupture release volumes are in all probability understated

In response to an information request, Enbridge has estimated a "Maximum Volume Out" in barrels between valves.[56] From another response to an IR it appears these volumes assume a 10-minute time estimate to detect/affirm a rupture and another 3 minutes to close the valves to avoid surge, plus drainage affected by the elevation profile between the remote control valves.[57] Ten minutes can pass very quickly in a control room emergency situation especially if mixed signals and procedures are complicated by lack of clear rupture alarms. While I am certain that Enbridge has made many changes in their control center in an attempt to improve rupture response, and apply their "ten minute rule," the lack of a clear rupture detection system that will not generate false alarms places a very high probability that false alarms will delay response in the control room to greater than 10 minutes, no matter Enbridge's best intentions.

The ten-minute rule "requires operators to shut down a line if a column separation cannot be resolved with[in] 10 minutes."[58] The ten-minute rule was supposed to have been imposed by Enbridge management following a similar pipeline crack rupture and major oil release from a pipeline rupture in 1991 on another Enbridge pipeline that confused control room operators by the issue of column separation that went on for several hours before isolation valves were closed.[59] While I can also appreciate Enbridge's attempts to improve their leak detection approach after the Marshall rupture, applying industry best practices and the five leak detection methods indicated by Enbridge's IR responses, will not be effective.[60] Based on my extensive experience in the area of pipeline leak detection, control center operators need SCADA computer tools that assist in rapid rupture detection and indication. Since Enbridge has not demonstrated that have properly or adequately improved in this area, there is a greater likelihood that volume release will thus be much greater than indicated upon rupture on a 30-inch pipeline, unless changes are made to the pipeline operation, such as eliminating column separation as a complication.

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[56] Enbridge Response to Ontario IR, Attachment 1 to Ontario IR 2.9.c.

[57] Enbridge Response to National Farmers Union IR No 2.1.e, p. 2.

[58] NTSB No. DCA10MP007 Marshall, MI July 25, 2010 failure, "Liquid Pipeline Accident – Marshall, Michigan, Group Chairman's Factual Report Human Factors," dated March 28, 2012, p. 23.

[59] NTSB, "Liquid Pipeline Accident – Marshall, Michigan Control Room and Supervisory Control and Data Acquisition (SCADA) Group Chairman Factual Report – SCADA Attachment 32 10-minute rules," dated April 10, 2012, p. 22 of 90.

[60] Enbridge Responses to Ontario IR No 1.44.b.iv, pp. 75 – 76, and NEB IR No. 3.10.c, pp. 27 - 29.

12) The emergency response plan and response times are not adequate for a high consequence area

Enbridge has indicated in several IR responses that travel times for response will be on the order of 1.5 to 4 hours.[61] These response times are completely unworkable for a pipeline located in so many high consequence areas. Enbridge needs to improve equipment staging sites and coordinate/commit appropriate personnel such that response times are significantly reduced for such high consequence areas along Line 9.

Sufficient detail has also not been provided as to the response if dilbit is released. The ERP/Oil Spill Response should distinguish between an ERP which focuses on saving lives and then property, versus oil spill response which focuses on reducing potential oil spill volume, then containment, then recovery. Oil spill response plans also need to address the situations where dilbit can sink such as was clearly shown in the Marshall, MI rupture, and now apparently in the Pegasus Pipeline rupture this past March at Mayflower, AR. Of course oil spill plans still need to address crudes where oil releases will float in water, such as with the lighter Bakken crudes.

B) Recommendations to NEB

Given the above general observations pertaining to the Line 9B Project, Accufacts recommends:

1) Hydrotesting should be required before Line 9 is reversed

Proper hydrotests should be performed on Line 9A and 9B before commencing the Reversal Project's operation to prove the integrity of the system to handle the demands of the Reversal Project. Based on the preponderance of information from the NTSB investigation, Accufacts finds that Enbridge has a culture of denial when it comes to the strengths of hydrotesting and a highly distorted over-reliance on ILI inspection on crack detection that has yet to be sufficiently proven to assure pipeline integrity from certain extensive SCC and/or corrosion fatigue cracking threats on Line 9.

Accufacts finds Enbridge's statements concerning the possible damage from hydrotesting are without technical merit, and appear to be attempts to misinform decision makers and the public. Recommended hydrotesting should obviously be performed to Canadian standards that are superior in their clearer prescriptive requirements compared to U.S. pipeline safety hydrotesting regulations. Canada has a multi-decade history and considerable experience in assuring performance of such proper hydrotesting of pipelines containing extensive cracking risks, such as SCC. As in any assessment method, depending on the threat, the pipeline should periodically be reassessed, even though such periodic maximum periods between such assessments are not specifically defined in Canadian pipeline safety regulations.

[61] Enbridge Responses to Equiterre IR No. 2.

2) The leak detection approach should be modified to focus on rupture detection in all modes of operation

Enbridge should design Line 9 to not operate in slack line operation. This will greatly improve the reliability of the MBS to avoid false alarms during normal operation. The leak detection approach should also be modified to focus on rupture detection during major transients that can be from line packing/inventory impacts associated with compressible hydrocarbons, during startup and shutdown, as well as normal operation. Procedures should be added that assure that such a rupture alarm <u>is never treated as a false alarm</u>. In other words, every rupture alarm should require shutdown, remote valve closure and pipeline field review to confirm no release occurred. Such modifications should not be expensive to implement.

3) Emergency response plan volume and timing should be extensively modified to reflect the high consequence areas

In reviewing the various IR responses Enbridge has not given sufficient attention to, or provided enough detail, that the response plans are appropriate for a pipeline rupture in such sensitive high consequence areas. It is possible that the company is waiting to see if the Project gets NEB approval. Regardless, prior to startup of the reversed pipeline, Enbridge should provide to the NEB an oil spill response plan in sufficient detail to demonstrate that the plan can be effective in the Eastern Canada environment for all the crudes that will be moved on Line 9.

IX. Summary

Integrating the Project's many documents supplied in the NEB process with the results of the Marshall, MI pipeline rupture investigation clearly indicates, in my opinion, that Enbridge has a culture where safety management seems not to be a critical component of their operation. In Canada the integrity management approach is seriously influenced/controlled by the Risk Assessment process that permits several methods to reduce risk, depending on the imperfection, such as ILI or pressure testing as applicable.[62] Surprisingly, Enbridge, in my opinion has not supplied sufficient information or incorporated the relevant NTSB recommendations that are intended to prevent failure from prevalent SCC coincident with general corrosion threats on Line 9.

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[62] "CSA Standards Z662-11, Oil and gas pipeline standards - N.10.3 Imperfections," Reprinted January 2012, p. 456.