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August 10, 2012

<u>**VIA EMAIL AND OVERNIGHT DELIVERY**</u>

Mr. David Barrett
Director, Central Region
Pipeline and Hazardous Materials Safety Administration
901 Locust St., Suite 462
Kansas City, MO 64106

Re: CPF 3-2012-5013 L6B Marshall Michigan – Enbridge Response to July 2012 Notice of Probable Violation and Proposed Civil Penalty

Dear Mr. Barrett:

Pursuant to 49 C.F.R. § 190.209(a), Enbridge Energy, Limited Partnership ("Enbridge") respectfully submits the enclosed response to the Notice of Probable Violation ("NOPV"), Proposed Civil Penalty and Proposed Compliance Order, dated July 2, 2012, as amended on July 5, 2012, in which PHMSA asserts certain violations of the Pipeline Safety Regulations, Title 49 Code of Federal Regulations.

As stated in the response, Enbridge has agreed to pay the penalty proposed by PHMSA and has begun the procedures to wire the funds through the Federal Reserve Communications System to the account of the U.S. Treasury. The response also offers Enbridge's views on the alleged violations for PHMSA's consideration.

Finally, please note that this response is timely, as per the extension of which we were notified by Ms. Renita Bivins.

Sincerely,

David H. Coburn
Attorney for Enbridge Energy, Limited Partnership

Enclosure
cc: Renita Bivins, Esq.

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ENBRIDGE™

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Re: CPF 3-2012-5013 L6B Marshall Michigan – Enbridge Response to July 2012 Notice of Probable Violation and Proposed Civil Penalty

Dear Mr. Barrett:

Enbridge Energy, Limited Partnership ("Enbridge") respectfully submits this letter in response to the Notice of Probable Violation ("NOPV"), Proposed Civil Penalty and Proposed Compliance Order, dated July 2, 2012, as amended on July 5, 2012, in which the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") asserts certain violations of the Pipeline Safety Regulations, Title 49 Code of Federal Regulations ("CFR").

The twenty-four violations proposed by the NOPV relate to a crude oil release of approximately 20,082 barrels on July 25, 2010 from Enbridge's 30-inch diameter Line 6B pipeline near Marshall, Michigan. The NOPV proposes a civil penalty of $3,699,200.

By this letter Enbridge agrees not to contest the proposed civil penalty, payment of which is currently in process. Enbridge understands its responsibilities under the federal pipeline safety laws and remains committed to full compliance with those laws and to the safe operation of its pipelines. Enbridge also understands the serious nature of the pipeline incident at Marshall, Michigan. It has assumed its responsibility for the clean-up of that spill and has learned from the incident. At the same time, Enbridge takes issue with many of the allegations set forth in the NOPV. It submits the information below in response to the proposed violations and respectfully requests that PHMSA take this information into consideration.

Enbridge Response to Item No. 1

The alleged violation relates to a corrosion inspection run conducted on October 13, 2007. The report for the run was received more than 180 days after the ILI run was completed (June 4, 2008) due to problems the vendor (PII) was having with the data. The report PII provided to Enbridge on June 4, 2008 ("June 2008 report"), for example, contained data configuration problems. Enbridge was able to conduct integrity programs on the pipeline using the data in the form received, and began doing so immediately upon receipt of the June 2008 report, but nonetheless requested that the data configuration problems be resolved. Enbridge's specific actions in response to that report included pressure restrictions and digs. In fact, excavation and repair began on June 25, 2008, only three weeks after receiving the June 2008 report. Pressure restrictions were initially imposed on December 17, 2008 following the June 2008 report, and additional restrictions were imposed on January 20, 2009, March 3, 2009, and April 29, 2009. All the while response actions were being undertaken, Enbridge continued to work through and assist the vendor with correcting the data configuration issues.

Following the 2007 ILI and June 2008 report, Enbridge continued to communicate actively with PHMSA on Line 6B. For example, Enbridge provided presentational updates in November 2009 and March 2010 regarding the status of integrity assessment and compliance initiatives. During this time, Enbridge also corresponded with PHMSA regarding a proposed Line 6B pipe replacement program. This dialogue advised PHMSA of the interim ILI assessments and the difficulties PII was experiencing in conducting interim ILI runs. Of note, due to such difficulties, Enbridge was proactively conducting ILI runs on a more frequent basis than the required 5-year assessment interval. Also, the delays in PII providing a satisfactory report to Enbridge following the 2007 ILI run were largely due to attempts to overlay and integrate differing ILI technologies, which Enbridge was requiring in order to better characterize line conditions, threat susceptibility and risk mitigation associated with Line 6B.

Enbridge maintains that there is no evidence or allegation that any delay in assessing the 2007 ILI run contributed in any way to the July 2010 failure. As a result of the 2007 ILI, Enbridge investigated and excavated over 300 corrosion features, in addition to imposing a Long Term Pressure Reduction on those features on July 15, 2010. Enbridge maintains that its actions were in accordance with PHMSA regulations given the issues associated with the vendor-provided data.

<u>Enbridge Response to Item No. 2</u>

Item No. 2 cites potential violations of two separate regulatory subparts: 195.452(h)(4)(iii)(H) and 195.452(h)(4)(iv). Because these two subparts contain different operative language and regulatory requirements, Enbridge addresses them separately below.

i. Enbridge Response to Proposed Violation of § 195.452(h)(4)(iii)(H)

Enbridge conducted numerous inspections of Line 6B prior to 2010 consistent with applicable PHMSA regulations set forth in Part 195 of 49 C.F.R. An inspection was conducted in February 2004 using an USWM tool. An initial report of this inspection was issued in May 2004, and Enbridge received a revised report in June 2004, which revealed the presence of external corrosion features on Line 6B. Enbridge and PII evaluated these features, and on June 14, 2004 Enbridge imposed a 525 psig pressure restriction on Line 6B in order to remediate risks posed by any features. No pressures in excess of 532 psig were noted from 2005 up until the time of rupture.

Enbridge calculated the pressure restriction selected using ASME-sponsored code B31G, 2009 edition, Manual for Determining the Remaining Strength of Corroded Pipelines: Supplement to ASME B31 Code for Pressure Piping, as applied to corrosion features. This is an approved method for calculating the remaining strength of the pipe for corrosion specified at 49 CFR §§195.452(h)(4)(i)(B), 195.452(h)(4)(iii)(D).

Thus, appropriate remedial action following the 2004 inspection – imposition of a pressure restriction – was implemented 121 days after completion of the inspection. Further, any corrosion features on the longitudinal seams had no bearing on the 2010 rupture of Line 6B. In fact, NTSB concluded without qualification that the 2010 rupture "did not occur at the longitudinal seam weld or in the weld heat-affected zone." Final NTSB Report, at 82. Accordingly, the statement in the NOPV that the 2010 rupture of pipe joint #217720 "result[ed]" from "reported corrosion ... anomalies" is inaccurate to the extent it attributes the rupture to seam weld corrosion (the type of corrosion covered by § 195.452(h)(4)(iii)(H)). More importantly, based on the preamble to 49 CFR 195.452[1], the intent of § 195.452(h)(4)(iii)(H) is to identify selective seam corrosion (a.k.a. seam weld corrosion). As indicated in the above-referenced documents, selective seam corrosion is a form of corrosion that affects only LF-ERW or lap welded longitudinal seam welds. However, pipe joint #217720 was a DSAW longitudinal seam, and thus, selective seam corrosion could not have occurred at this pipe joint.

Similarly, there is no evidence that seam weld corrosion features contributed in any way to environmental harm of any kind, or that the corresponding pressure restrictions imposed by Enbridge were in any way insufficient to address the presence of the features discovered at that time. To the extent that the fines in this case have been increased due to the actual rupture at issue, such an increase is unwarranted by any failure by Enbridge to adhere to PHMSA's regulations, including any minor delay in addressing the corrosion features found on the seam welds in 2004.

Further, the NOPV does not state whether it considers the pressure limits imposed in 2004 to be insufficient remedial measures. Having failed to allege that the pressure restrictions were insufficient, it would be unreasonable and unfair for PHMSA to impose fines based on such a claim in the absence of notice as to how the action taken by Enbridge under the regulation allegedly was deficient.

To the extent that the Agency nevertheless contends that corrosion features on the pipe joint #217720 were required to be excavated, Enbridge respectfully disagrees. PHMSA, in promulgating § 195.452(h), specifically acknowledged in response to comments by API that "operational changes" – rather than physical repairs to the pipeline itself – could be sufficient to satisfy the requirements §452(h). Given this history and the language of the regulation itself there is no basis for a finding of violation based on Enbridge's good-faith imposition of pressure limits as a prompt, practical method to remediate information obtained in the 2004 ILI (as well as subsequent ILI's conducted on Line 6B).

ii. Enbridge Response to Proposed Violation of § 195.452(h)(4)(iv)

Enbridge conducted numerous inspections of Line 6B, consistent with applicable PHMSA regulations set forth in Part 195 of 49 C.F.R. An inspection was initially conducted in

[1] *See also* API 1160, PHMSA FAQs, PHMSA Selective Seam Corrosion Fact Sheet, and PHMSA TT0 Number 5.

September 2005 using a USCD Crack Tool, but that inspection failed because of incorrect tool parameter programming. The test was conducted again in two runs in October and December of 2005.

In March 2006, Enbridge received a report of those runs and evaluated the crack features on pipe joint #217720 through a detailed and industry accepted engineering critical assessment.[2] The features were found to have the necessary safety factor for reliable operation and did not require excavation in accordance with Enbridge's pre-established criteria. Enbridge completed extensive remediation programs based upon the 2004 USWM ILI and 2005 USCD ILI runs of all features meeting such criteria.

The regulation requires only that Enbridge "evaluate any condition ... that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation." The regulation does not otherwise require that all anomalies identified through ILI assessments be scheduled for remediation. Since the crack feature at joint #217720 did not meet Enbridge's pre-established criteria, Enbridge concluded that it was not a condition requiring remediation.

Section 195.452(h)(4)(iv) itself imposes no requirement that goes beyond current industry practice as followed by Enbridge. Further, according to NTSB, Section "195.452(h) fails to provide clear requirements for performing an engineering assessment and remediation of crack-like defects on a pipeline." Final NTSB Report, at xiii. As a result, Enbridge's response to the ILI run was consistent with the regulations as promulgated.

Enbridge recognizes that a retrospective review (in 2010 after the rupture) of the results provided in the 2006 report concluded that certain anomalies should have been characterized as a "crack field" in 2005. As a result of this mischaracterization by PII, Enbridge had no actual knowledge of the crack fields until after the 2010 rupture. This failure to identify the crack fields played a critical role in the rupture. NTSB concluded that "PII's 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." NTSB Final Report at 93. According to NTSB, if the features had been properly characterized, that the largest such feature "would likely have been excavated by Enbridge in 2005." *Id.*

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[2] CorLAS is an industry accepted engineering critical assessment method developed by DNV through the work of PRCI. This software can be used to determine the predicted critical pressure of both blunt anomalies (e.g., corrosion, other metal loss) and sharp anomalies (e.g., cracks and crack-like anomalies). The model uses inelastic fracture mechanics to calculate the predicted critical pressure of toughness-dependent flaws. Enbridge inputs conservative material properties and flaw dimensions and utilization of this assessment method outputs the predicted critical pressure. A safety factor is then applied to the result to ensure continued reliable operations.

Further, CorLAS has been tested against actual burst test data and has been shown to be able to accurately predict failure pressure of cracks and crack-like flaws. A recent study completed in 2009 by Rothwell and Coote demonstrated CorLAS was an accurate model for predicted critical pressure for cracks.

Enbridge Response to Item 3:

Enbridge's model of the worst case volume out calculation was designed to comply with the requirements of 49 CFR § 194.105. In practice, the methodology used has resulted in a modeled estimate of lost volume that is conservative and that exceeds actual historical release amounts.

For example, actual release volume for U.S. mainline incidents with release volume larger than 1000 bbl from 1997-2011 is much less than Enbridge's modeled volume out calculations. In fact, volume out modeled calculations have exceeded actual release amounts for all incidents, except for the Marshall incident. Likewise, Enbridge's response time to shut down Line 6B following the Marshall incident is not reflective of Enbridge's quick response to other mainline incidents. The average response time to prior mainline instances was taken into account in Enbridge's modeled volume out calculation and supports the basis of that calculation.

Further, the method of volume calculation used by Enbridge is industry standard for risk assessments. For example, Enbridge presents its volume out calculation in 2006 and 2008 IPC (IPC2006-10380 and IPC 2008-64290). This method was first presented by Mohitpour M. et al. in 2004 International Pipeline Conference (Valve Automation for Oil Pipeline Safety", IPC2004-0022 Proceedings of the International Pipeline Conference, Calgary, Alberta) and was also published as recently as 2009 in Pipeline and Gas Technology as an appropriate method for volume out calculations. This volume calculation method is also similar to what is used by other industry leaders in their risk analysis, including, but not limited to, American Innovations, Eagle Information Mapping, and Dynamic Risk.

Operating scenarios, such as personnel compliance with internal procedures, have not been included in mainline risk assessment models by industry, nor by Enbridge. In the case of the Marshall incident, for example, the estimated response time proved to be different than predicted, principally due to the fact that Control Room personnel failed to follow procedures which were intended to be implemented. The risk assessment model is therefore intended to ensure/presume compliance with procedures in future events. If a risk assessment model were to account for non-compliance with internal procedures, worst-case scenario volume out calculations would be unrealistically extreme and provide no practical value in estimating actual worst case conditions and/or for assessing necessary response.

Enbridge Response to Item 4

Item No. 4 focuses on potential violations of § 195.452(j)(2), which address an operator's obligation to conduct periodic evaluations as needed to assure pipeline integrity.

In compliance with this requirement, Enbridge conducted numerous inspections of Line 6B (as well as other lines). Item No. 4 itself lists the following assessments of Line 6B:

- 2004 USWM
- 2005 USCD
- 2007 MFL
- 2009 USWM

In addition to the assessments identified above, Enbridge conducted a 2004 Geopig, 2005 CTool, 2007 CTool, and 2009 Caliper inspections. Enbridge was also conducting an ongoing inspection of Line 6B in July 2010 at the same time the rupture occurred. Thus, there appears to be little question that Enbridge has conducted frequent, periodic evaluations of pipeline integrity as required by subparagraphs 195.452(j)(1) and (2). Similarly, there is little question that Enbridge has based its frequency of evaluations on the correct regulatory factors specified in paragraph (e) of § 452 (which are incorporated by reference in subparagraph (j)(2).[3]

Item No. 4 of the NOPV asserts that that Enbridge, among other things, did not integrate the information from the assessments it conducted. The NOPV, however, provides no specific examples of any such failures, other than a broad, conclusory statement that the assessments in question were "evaluated independently and not integrated in a fashion that assures pipeline integrity." The sections of the regulations being referenced in the NOPV are also not prescriptive, i.e., they do not specify that one ILI data set should be overlaid with another ILI data set.

As a result, Enbridge respectfully disagrees with the agency's characterization of the company's evaluation process. Enbridge's crack inspection and integrity dig program on Line 6B during the years 2005 to 2010 was conducted in compliance with industry standards and PHMSA regulations. That program integrated recognized approaches to investigate the accuracy and performance of the USCD ILI tool, and was based on extensive information collection, calibration, integration and analysis. Specifics of this process are set forth in detail at pages 5 to 12 of Enbridge's Party Submission dated May 22, 2012, which was submitted in connection with the NTSB investigation of the Marshall accident, and which is attached hereto ("Enbridge's Party Submission").[4]

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[3] These factors include (i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate; (ii) Pipe size, material, manufacturing information, coating type and condition, and seam type; (iii) Leak history, repair history and cathodic protection history; (iv) Product transported; (v) Operating stress level; (vi) Existing or projected activities in the area; (vii) Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic); (viii) geo-technical hazards; and (ix) Physical support of the segment such as by a cable suspension bridge.

[4] As detailed in that Submission, since the 2010 accident, Enbridge has identified improvements in the process of conducting assessments of ILI features, including consideration of corrosion ILI data that is coincidental with crack ILI data. The two most significant areas identified for improved data integration in the future are:

- Enbridge did not utilize the 2004 USWM data to investigate whether the wall thickness value used in the crack ECA calculations (taken from the crack USCD ILI report) for pipe joint #217720 was accurate / appropriate. Enbridge now utilizes the lesser of the value obtained through ILI assessments or nominal wall thickness.

- Enbridge did not utilize the 2004 USWM data to identify that the crack features reported on pipe joint #217720 were associated with metal loss. Field calibration processes were relied upon to identify if adjustments to the crack ECA or dig

Further, while it is true that NTSB concluded that an integrity program should include a procedure to account for wall loss due to corrosion when evaluating ILI crack-tool-reported data, *see* NTSB Final Report, at 89, actual regulatory requirements found in Part 195, however, nowhere indicate that that such a specific procedure is required. In fact, the NTSB Report also concluded "that 49 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." Final NTSB Report, at 85.

As a result, the NSTB further recommended that PHMSA "revise 49 CFR 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or SCC as applicable." *Id.* at 86.

To the extent that such changes are implemented in the future, Enbridge will comply fully with them. During the period at issue here, however, Enbridge in fact was integrating data to the extent required by applicable regulations as promulgated and cannot be held responsible for any alleged failure to comply with requirements not actually promulgated or plainly set forth. The NOPV itself provides no example of any such integration requirement in Part 195. Nor does any commonly accepted industry standard require the type of analysis that NOPV now apparently contends is required.

In fact, Enbridge's integrity management standards meet or exceed industry practice in all respects. Enbridge's practices, for example, are fully consistent with those set forth in documents such as API 1160 and API 1163, which identify calibration of ILI data through field NDE assessments as an appropriate process. Retroactive application of NTSB's views, reached with value of hindsight and without any of the normal notice and comment normally associated with the promulgation of new regulatory requirements would be patently unfair and without any valid legal basis. At a minimum, such retroactive application of a new standard that does not reflect either the requirements of the PHMSA rules or industry practice cannot provide a basis for imposing the maximum penalty, as PHMSA has proposed.

With respect to the other allegations of the NOPV, Subparagraph 195.452(j)(2) specifically refers operators to preceding subparagraph (g) for factors relating to more specific types of information analysis that an evaluation should consider. Subparagraph (g) in turn provides that in periodically evaluating the integrity of each pipeline segment, an operator must

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selection criteria were required. Enbridge has implemented an approach to specifically overlay all ILI data sets to identify locations of coincident features. An expert based decision is then made regarding mitigation actions.

analyze "all available information" about the integrity of the entire pipeline and the consequences of a failure. Subparagraph (g) specifically lists the following information that should be analyzed:

- Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;
- Data gathered through the integrity assessment required under this section;
- Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and
- Information about how a failure would affect the high consequence area, such as location of the water intake.

Enbridge has developed and formalized various procedures and processes to integrate all of the information identified above in considering the frequency of integrity re-assessments. These processes are described in Enbridge's HCA Management Plan, which was audited by PHMSA in 2004, 2006 and 2011. Examples of key programs include:

- Corrosion Growth Rate Plan
- Corrosion Assessment Interval Plan
- Cathodic Protection Program
- Internal Corrosion Control Program
- Crack Management Plan
- Mechanical Damage Management Plan

Further, Enbridge's actual practices in fact take into account the information specified Subparagraph 195.452(g). For example, with respect to the first bullet above, Enbridge's Mechanical Damage Management Plan incorporates results from the third-party damage algorithm of the Enbridge mainline risk model, which includes patrols and surveillance to influence the mechanical damage in-line inspection re-assessment intervals.

With to respect to the second bullet, Enbridge's Corrosion Assessment Interval Plan, Crack Management Plan, and Mechanical Damage Management Plan integrates all of the information from previous hydrotests and in-line inspections in order to determine and schedule re-assessment intervals.

With respect to the third bullet, the Cathodic Protection Program integrates all cathodic protection survey information. The Internal Corrosion Control Program also integrates all internal corrosion monitor information, pipeline flow conditions and product types. Both Programs support, and are a direct input into, the Corrosion Assessment Interval Plan which determines the corrosion in-line inspection re-assessment intervals.

With respect to the final bullet, Enbridge's mainline risk model identifies direct and indirect high consequence areas that would be impacted in the event of a rupture by considering volume-out profiles and the proximity to water transport mechanisms. Corrosion Assessment

Interval Plan, Crack Management Plan and Mechanical Damage Plan identify how high consequence areas are considered for setting appropriate re-assessment intervals.

Enbridge Response to Item 5:

This item alleges that Enbridge failed to correct a "condition" that could affect the safe operation of Line 6B within a reasonable time of the condition's discovery, as provided by § 195.401.

To the extent that the "condition" that could affect safe operation was the rupture itself, it is undisputed that Enbridge operators did not discover this condition until approximately 11:17 a.m. on July 26. It is similarly undisputed that upon discovery that a rupture had occurred, Enbridge employees reacted rapidly and within a reasonable time as required by § 195.401.

To the extent that the "condition" discovered was the sounding of alarms and related instrument readings, this Item essentially alleges a failure to follow company procedures in response to the alarms. The Company has acknowledged that its response to the alarms that sounded and to related instrument readings was not consistent with company procedures. These failures, however, are fully addressed in Item Nos. 6, 7 and 8, which address failures to follow proper procedures in light of the same alarms and other instrument readings described in Item No. 5.

Enbridge Response to Item Nos. 6-10

Items 6-10 allege Enbridge's failure to comply with various internal procedures. In response, Enbridge reiterates that the closeness in time between the planned shutdown on July 25 and the accidental rupture caused the experienced operators on duty during the afternoon of July 25 to misinterpret the alarms that sounded and associated data as a column separation. As a result of this unusual coincidence of events, positive identification of the crude oil release did not occur promptly. Enbridge subsequently conducted a comprehensive self-examination following the accident, and has made a number of significant changes to applicable procedures and organizational assignments. These changes are set forth in detail at pages 12 to 15 of Enbridge's Party Submission.

Enbridge Response to Item 11

Item No. 11 alleges Enbridge's failure to evaluate its public awareness program. Enbridge maintains that, in accordance with industry recommended practices, it had in place a process to review the annual implementation (internal) of the effectiveness of Enbridge's Public Awareness Plan ("PAP) at the time of the Marshall incident. As stated in PHMSA's accompanying Report, the stakeholder audiences did not act in accordance with the expectations and communications that were provided to them through the PAP. Enbridge has subsequently made adjustments to its PAP to prevent similar problems in the future. Responsive adjustments regarding public awareness are described at pages 14 and 15 of Enbridge's Party Submission. Further, PHMSA conducted a subsequent inspection of Enbridge's Public Awareness Program in All issues raised during the July 2011 audit have been resolved.

Enbridge Response to Item No. 12

This item alleges that Enbridge operated Line 6B prior to correcting an unsafe condition. The allegations of this item closely resemble those of Item No. 5 above, which alleged a failure to correct a "condition" that could affect the safe operation of Line 6B within a reasonable time of the condition's discovery. Items 5 and 12 each allege violation of the same regulation, §195.401(b).

Item No. 12 specifically refers to the "First Restart" of Line 6B (attempted at approximately 4:04 a.m.). The operative "condition" alleged appears to be the rupture itself. The allegation appears to be it was a violation of § 401(b) to attempt to restart the pipeline knowing that a rupture had occurred.

As with Item No. 5, however, it is undisputed that Enbridge operators did not discover the rupture until approximately 11:17 a.m. on July 26. Thus, the First Restart occurred prior to the "discovery" that would trigger application of § 401(b).

To the extent that the "condition" referred to in Item No. 12 was the sounding of alarms in connection with the First Restart, this Item essentially alleges a failure to follow company procedures in response to the alarms. The Company has acknowledged that its response to the alarms that sounded and to related instrument readings was not consistent with company procedures. These failures, however, are fully addressed in Item Nos. 13, 14 15 and 16, which deal with failures to follow proper procedures in light of the same alarms described in Item No. 12.

Enbridge Response to Item Nos. 13-16

Items 13-15 allege Enbridge's failure to comply with various internal procedures. Enbridge recognizes that, although the pipeline was shut down following the First Restart, certain steps set forth in Enbridge's CCO General Operating Standards were not implemented.[5] Enbridge conducted a comprehensive self-examination following the July 25 incident, and has made a number of significant changes to applicable procedures and organizational assignments. These changes are set forth in detail at pages 12 to 15 of Enbridge's Party Submission.

Enbridge Response to Item No. 17

Item 17 alleges that Enbridge failed to correct a "condition" that could affect the safe operation of Line 6B within a reasonable time of the condition's discovery, as provided by § 195.401.

To the extent that the "condition" that could affect safe operation was the rupture itself, it is undisputed that Enbridge operators did not discover this condition until approximately 11:17 a.m. on July 26. It is similarly undisputed that upon discovery that a rupture had occurred, Enbridge employees reacted rapidly and within a reasonable time as required by § 195.401.

[5] *See* Internal Investigation Review, at 38-39 (Feb. 28, 2011).

To the extent that the "condition" discovered was the sounding of alarms and related instrument readings following the Second Restart, this Item essentially alleges a failure to follow company procedures in response to the alarms. The Company has acknowledged that its response to the alarms that sounded and to related instrument readings was not consistent with company procedures. These failures, however, are fully addressed in Item Nos. 18 and 19, which address failures to follow proper procedures in light of the same alarms and other instrument readings described in Item No. 17.

Enbridge Response to Item Nos. 18-19

Items 18-19 allege Enbridge's failure to comply with various internal procedures in connection with the Second Restart. Enbridge recognizes that, although the pipeline was shut down following the Second Restart, procedures set forth in Enbridge's CCO General Operating Standards were only partially followed. Enbridge conducted a comprehensive self-examination following the July 25 accident, and has made a number of significant changes to applicable procedures and organizational assignments. These changes are set forth in detail at pages 12 to 15 of Enbridge's Party Submission.

Enbridge Response to Item Nos. 20-21

Enbridge's response to Items 20-21 are addressed through its Responses to 6-8, 13-16, 18 and 19 above.

Enbridge Response to Item Nos. 22 - 23

Items 22-23 allege violations associated with Enbridge's incident report. Enbridge filed its original Accident Report within the 30 day timeline as required in 195.54 based on best available preliminary information,

The NTSB launched an investigation into the Marshall incident, in which Enbridge, along with PHMSA and other participating stakeholders, entered into a party agreement which precluded Enbridge or other party members from making their own determination on evidence until the investigation concluded. All party members also agreed upon a common factual account and determination into the cause and related factors surrounding the incident.

Enbridge continued to consult with the NTSB and communicated to PHMSA the NTSB's position regarding the release of further information that would trigger PHMSA Accident Report updating. With NTSB approval, Enbridge updated its accident reporting with known changes and incorporated those into supplemental narrative revisions.

PHMSA recognizes that the investigation process in many cases takes longer than 30 days to conclude, and provides an operator the ability to file initial, supplemental, and final reports as the investigation reveals new facts, findings or informational changes.

The intent of the investigation was to ensure that the details identified within PHMSA Accident Report were accurate. Further, in this instance, the NTSB was leading the investigation as opposed to Enbridge. Accordingly, Enbridge reported to the extent allowed under NTSB requirements. With the July, 2012 release of the NTSB report, Enbridge will file revisions the Accident Report which take into account the NTSB factual reports.

Enbridge Response to Item 24

Enbridge's response to Item No. 24 is addressed through its Responses to 6-8, 13-16, 18 and 19 above. Enbridge further notes that PHMSA's Violation Report finds that Enbridge acted in good faith in assigning a qualified individual to directly observe the unqualified individual's performance. *See* PHMSA Violation Report, at 165.

* * *

Enbridge appreciates this opportunity to respond to PHMSA's claims. While Enbridge has opted not to contest the imposition of the proposed monetary penalty, we respectfully request that PHMSA take the above information into account.

Sincerely,

Richard Adams
Vice President, U.S. Operations
Enbridge Energy, Limited Partnership

May 22, 2012

ENBRIDGE ENERGY, LIMITED PARTNERSHIP PARTY SUBMISSION INVESTIGATION OF JULY 2010 LINE 6B ACCIDENT NEAR MARSHALL, MICHIGAN; NTSB ID: DCA 10MP007

PREAMBLE

Enbridge Energy, Limited Partnership ("Enbridge") appreciates the opportunity to provide this Party Submission. Enbridge has also appreciated the opportunity to work side-by-side with other Party members in the pursuit of the facts of this accident with the common objective of making improvements in the safety of Enbridge's operations as well as those of the entire pipeline industry. As of the filing of this Party Submission, Enbridge understands that not all Factual Reports have been completed as Enbridge continues to respond to inquiries and requests for information from certain fact report working groups. As a result, Enbridge is not certain whether the conclusions stated in this Submission will necessarily accord with the findings of all of the Factual Reports in all respects. If, upon review of all Factual Reports, Enbridge determines that it is necessary to address any factual finding, Enbridge will promptly file a supplemental Party Submission.

1. INTRODUCTION

Enbridge's Line 6B is a 30-inch diameter pipeline that runs from Griffith, Indiana, to Sarnia, Ontario. Constructed in 1969, Line 6B has an average daily capacity of 283,000 barrels. The line, which generally carries light synthetic and heavy and medium crude oil, supplies refineries in Ohio, Michigan, Pennsylvania and eastern Canada.

Line 6B was operating normally on July 25, 2010 when it was shutdown to facilitate a routine scheduled delivery of product into Stockbridge, Michigan. At approximately 17:58, at the initiation of the scheduled shutdown, a loss of containment occurred near mile post 608 (the "Accident"). The Accident occurred as the result of a confluence of events that collectively contributed to the release of approximately 20,082 barrels of crude oil. The Accident site is located approximately 0.6 miles downstream of Enbridge's Marshall pumping station.

Enbridge has determined the following as a result of its internal investigation and participation in the NTSB investigation:

- The probable cause of the loss of containment was stress corrosion cracking ("SCC") in the pipeline.
- Enbridge has a well-established and comprehensive integrity management program implemented on Line 6B and has conducted various in-line inspections ("ILI") of Line 6B since 1976. In particular, between 2004 and 2009 Line 6B was inspected three times for metal loss, once for cracking, three times for geometry features and once using an innovative approach for identifying mechanical damage. Based upon the comprehensive data from all the inspections, the potential for the release at the location near Marshall was neither anticipated nor foreseen. The SCC feature identified as likely

responsible for the leak represented an unusual circumstance, far more severe than anything else identified or projected on the pipeline before or since the Accident.

- The NTSB's Materials Report showed no significant internal corrosion in the ruptured pipe joint.

- Although the maximum operating pressure for Line 6B was 624 psig, Enbridge was operating the pipeline with a maximum discharge pressure of 523 psig at the Marshall station prior to the Accident. The maximum-recorded discharge pressure at the Marshall station around the time of the failure was 486 psig, well below both the maximum operating pressure of Line 6B and the maximum discharge pressure at the Marshall station.

- The unanticipated failure occurred during a scheduled shutdown, when a significant loss of pressure is normal. Thus, the initial mass balance system (MBS) alarm that occurred in the main control room at the time of the scheduled initiation of the shutdown was attributed to a column separation after being investigated by an MBS analyst. (Column separation, a well-known operating condition on liquids pipelines, forms when depressurization of a section of pipe occurs and some of the oil in the pipe is vaporized and moves from liquid to vapor state.) Because the frequency of alarms during a shutdown process was not unusual, the experienced crew did not regard the alarms, by themselves, to suggest a loss of containment.

- When the scheduled restart of Line 6B began at 4:04 a.m. on July 26, the new shift in the control room also attributed the MBS alarms to a column separation. Because of the unusual circumstances surrounding the pipeline failure described above and subsequent human errors, the trouble-shooting of very experienced personnel in the control room over the next seven hours focused on resolving the multiple alarms and column separation rather than a potential loss of containment.

- Hours before the scheduled restart of Line 6B, numerous 911 reports from members of the public about a possible gas leak in the area were made, prompting both the Marshall City and Marshall Township Fire Departments to investigate these reports. Neither team of investigators located the source of the odor and departed the area without resolution or report to Enbridge (or to any other local oil or gas company). As part of Enbridge's ongoing public awareness program, both fire departments had recently participated in a safety awareness training program conducted by Enbridge.

- The torrential rains in the area immediately prior to the failure (totaling over 5 inches) accelerated the spread of the release into Talmadge Creek and thereafter into the Kalamazoo River, as well as significantly hindered the efforts to limit and clean up the release. Had this amount of rain not fallen before the Accident, or had Enbridge received notification of the Accident at any time before the early morning restart of Line 6B, the oil would not likely have reached even Talmadge Creek.

As a result of an unusual coincidence of events described above, positive identification of a crude oil release did not come until approximately 11:16 a.m. on July 26 – over 17 hours after the Accident occurred – when Enbridge's Control Center Operations ("CCO") received a call from a local natural gas company advising of oil in a creek near Division Road in Marshall.

Enbridge management responded immediately. Within a half hour, at 11:45, an Enbridge first responder confirmed oil on the ground and called the CCO emergency line. Regional management in Chicago contacted Enbridge executive management and initiated Enbridge's emergency response protocol, including calls to enlist internal and external resources and to notify the appropriate regulatory agencies. Remote controlled valves were closed by the CCO, thereby confining the failure within a three-mile section.

Along with a team from Enbridge's regional offices throughout North America, Patrick D. Daniel, Chief Executive Officer of Enbridge Inc., arrived on scene that evening and spent the next two months on site overseeing the extensive containment efforts, meeting with federal, state and local officials, and working with health care providers, community leaders and affected individuals to ensure that Enbridge put things right. Mr. Daniel pledged that Enbridge would take full responsibility to address the impacts of the release on the natural environment and on individuals and businesses in Marshall, Battle Creek and the surrounding area. Enbridge is doing so.

Given the dedication of Enbridge's employees, the experience of its pre-identified emergency crews, the efforts of the approximately 1,200 field personnel deployed at the peak of the response (including 500 Michigan residents) and the local, state and federal officials who worked with Enbridge, the release was quickly contained. Within one week, Enbridge succeeded in removing most of the released oil off the Kalamazoo River. By the end of August 2010, Enbridge had met the Unified Command's goal of cleanup at the leak site and along Talmadge Creek. By the end of September, Enbridge had completed the bulk of the cleanup. Enbridge continues with remediation efforts, working with the Environmental Protection Agency (EPA), the Michigan Department of Natural Resources and Environment and other officials to restore the affected areas and to establish a long-term monitoring plan.

In September 2010, Mr. Daniel testified before Congress about the Accident. He said in part: "Once the investigations into this incident have been completed, Enbridge is fully committed to addressing whatever changes might need to be implemented so that we and others in the industry can avoid a repeat of this incident. We intend to work with you to ensure that the Committee's concerns and those of the communities in which we operate are fully addressed." Enbridge is doing so.

Since the Accident, Enbridge has reviewed all relevant pipeline integrity documentation to assess what may have caused the pipe section to fail and to prevent the recurrence of this type of loss of containment anywhere on the Enbridge system. Numerous process and procedure modifications and improvements have been implemented by Enbridge. Examples of these actions are described in section 5.

2. BACKGROUND ON ENBRIDGE

Enbridge is a leader in the energy delivery industry in North America. Enbridge's core values of integrity, safety and respect guide the way it makes decisions and conducts business. Enbridge strives to operate with high standards in all interactions with customers, investors, employees, partners, regulators and in the communities through which it operates. Moreover, Enbridge is committed to ensuring compliance with applicable laws in every jurisdiction in which it operates.

Enbridge has grown its business substantially over the past 60 years. Today, Enbridge operates one of the world's longest petroleum liquids pipeline systems, serving customers throughout Canada and the United States. Last year, Enbridge delivered approximately two million barrels per day of oil to markets throughout the United States and Canada. The Enbridge pipeline system currently delivers more than 12 percent of the total daily imports of crude oil into the United States.

As the operator of North America's largest crude oil pipeline system, Enbridge is committed to safely and reliably delivering energy to people across the continent. The goal is to have no leaks or releases, ever. Based on miles of pipeline Enbridge operates, its line break rate is well below the industry average. The substantial sums spent annually on pipeline integrity programs support activities such as corrosion control, monitoring and advanced inline inspection technologies that provide a view of a pipeline at fractions of an inch. Enbridge also runs regular ground and aerial pipeline patrols, and maintains a comprehensive program of digs to test the integrity of its pipelines. In addition, Enbridge has developed strong public awareness programs.

3. FIELD RESPONSE TO THE ACCIDENT

Approximately 20,082 barrels of crude were released as a result of the failure. Some of the oil entered Talmadge Creek and from there a lesser amount entered the Kalamazoo River; the rest remained in the vicinity of the failure. There were no fatalities.

Upon first notification of the release of oil on the morning of July 26, the pipeline was further isolated, which as noted above already had been shut down for a planned delivery. That day, crews began installing containment boom that had been pre-positioned in Marshall. The initial focus during the first week was collecting the oil from the Kalamazoo River and then recovery of free oil from the immediate ground around the leak site.

To address the needs of the local communities and to make information available as quickly and reliably as possible, Enbridge began that day contacting residents in the areas of greatest direct impact along Talmadge Creek. By 9:45 p.m. on July 26, a hotline was set up and the number was provided to the local media to publicize. Enbridge also quickly published a website for the Accident – www.response.enbridgeus.com – where area residents could find up-to-date information on the Accident, measure the Enbridge's response to it and submit comments or questions. Within two weeks, Enbridge had opened two community centers staffed with a team of employees to work directly with residents to provide appropriate assistance.

After arriving on scene on July 26, Mr. Daniel made it a point to meet with as many people as possible, often in their homes, so that they could share their concerns directly with him and so that Enbridge could respond as quickly as possible to address their concerns. Enbridge established processes to provide direct assistance for pre-paid hotel stays, equipment and services; reimburse for cost of living expenses and other qualified expenses incurred directly as a result of the leak, voluntary evacuation and clean-up activities; receive and pay claims for property and personal damages (such as business interruption, nuisance and inconvenience and temporary land access and use); pay medical expenses for those individuals without insurance or a primary care physician; and purchase homes from adversely affected individuals at the pre-release appraisal value.

4. PIPELINE INTEGRITY, INSPECTION TECHNOLOGY AND ANALYSIS

Information provided within the NTSB Materials Report suggests that the principal metallurgical feature that led to the July 2010 Line 6B failure near Marshall, Michigan was environmentally assisted cracking (commonly referred to as stress corrosion cracking). In this section, we describe the integrity actions that Enbridge undertook as part of the crack inspection and mitigation program it implemented from 2005 to 2010 on Line 6B.

With the primary cause of the failure identified as stress corrosion cracking, the draft NTSB Integrity Management Factual Report that Enbridge has reviewed suggests that the appropriate methodology for ILI data analysis in order to detect and assess the nature and extent of stress corrosion cracking is to add crack depth to corrosion depth if these features are coincident. Enbridge does not believe that simply adding crack depth to corrosion depth reflects industry practice (either at the time of the Accident or today) and that this suggestion does not provide a practical course of action for the future. Because of this apparent disagreement over a material issue of Integrity Management, this section of the Enbridge Party Submission provides a detailed review of the engineering technologies, processes and practices relevant to this area and how they were appropriately applied by Enbridge in accordance with regulatory and industry standards with respect to Line 6B.

Background. The pipeline industry uses sophisticated ILI technology to identify features that may suggest, indicate, contribute to or result in a loss of pipeline integrity. These tools are generally threat-specific:

- Magnetic Flux Leakage and straight beam Ultrasonic: used to detect metal loss, corrosion and gouges
- Caliper tools: used to detect dents and other geometric anomalies
- Ultrasonic Shear Wave: used to detect cracks and other linear features

Two industry documents describe the processes for ILI vendors to follow in order to develop their performance specifications: the NACE International RP0102 In-Line Inspection of Pipelines (revised in 2010) ("NACE 0102") and the American Petroleum Institute ("API") Standard 1163 In-Line Inspection Systems Qualification Standard ("API 1163"). API 1163 requires ILI tool vendors to identify in their reporting specifications any physical or operational factor or condition that may limit detection thresholds and sizing accuracies. If it is known that corrosion could influence the detection or sizing capability of the crack-detecting ultrasonic shear wave tool, that fact should be included in the ILI vendor's performance specifications. Enbridge's tool vendor, Pipeline Integrity International ("PII"), developed its Ultrasonic Crack Detection ("USCD") tool in accordance with API 1163.

No indication of such a limitation had been promulgated by ILI vendors. Also, the state of the art in ILI data analysis did not contemplate this as an issue. As a pipeline operator, Enbridge is aware that there could be conditions or circumstances that affect the accuracy of the collected ILI data. Such items that could impact ILI data quality are investigated by way of field excavation verification and ILI data calibration processes.

Enbridge Inspection and Analysis in 2005-2006. A comprehensive integrity assessment, testing and remediation program had been underway on Line 6B for many years prior to the Accident. In accordance with 49 CFR 195.452(e), Enbridge completed a risk assessment on Line 6B that integrated all relevant integrity data sets and supported the ongoing implementation of the monitoring and mitigation plan. Specific to fatigue and environmentally assisted cracking, the risk assessment supported the scheduling of a baseline crack assessment in 2005 using the shear wave ultrasonic crack tool (USCD) supplied by PII. Figure 1 below is a summary of the key integrity data relevant to the cracking threat that was integrated to complete the risk assessment.

Figure 1

ENBRIDGE

Enbridge Pipelines - Crack Suseptibility Analysis
PRIORITY RANKING TABLE

This table describes a grading system for Crack ILI of the Enbridge pipelines in their trap to trap segments. Each of the segments has been evaluated with respect to their history of crack failures, their long seam weld type and manufacturer, occurrences of SCC, and their typical operating pressure cycling history. Each of these categories has been graded by a senior engineer in the Pipeline Integrity Department using a numbering system between 1 and 5. 1 represents the highest contribution to crack susceptibility and 5 represents the lowest contribution to crack susceptibility. Some of the sections of the pipeline will have multiple gradings in some of the categories where multiple grading criteria apply. The overall likelihood grading is determined by adding up the lowest score in each of the four columns. The segment with the lowest overall likelihood grading would therefore have the highest likelihood of cracking susceptibility.

The last column of the table lists the recommendation for in-line inspection of that particular trap to trap segment. While the susceptibility likelihood and consequence rankings provide the bulk of the reasoning for this recommendation, additional considerations for select segments are also provided in the comments column.

Grading Criteria

Pressure Cycling
1. Frequent start stop operation
2. Significant fluid property changes
3. Infrequent start stop operation
4. Insignificant fluid property changes

Weld Type/Manuf.
1. Manufacturing flaws in the long seam that have initiated ruptures.
2. Manufacturing flaws in the long seam that have initiated leaks.
3. Manufacturing flaws in the long seam that have initiated fatigue
4. Manufacturing flaws in the long seam that have not initiated fatigue
5. No history of manufacturing flaws at the long seam.

Previous Crack Failures
1. Ruptures
2. Leaks
3. Exhibited Fatigue
4. No Fatigue
5. No Crack Failures

Field Results for SCC
1. Frequent SCC discovered
2. Less Frequent SCC discovered
3. Infrequent SCC discovered
4. No SCC reported

Additional Comments
Comments stating any other relevant information as to why the section is being considered for ILI or not.

Recommendation Level
1. Recommendation level 1 dictates the need to conduct ILI immediately
2. Recommendation level 2 indicates that the potential need for monitoring is high. These segments will be prioritized for the probabilistic susceptibility assessment process.
3. Recommendation level 3 indicates a low need for on-line monitoring but will be evaluated using the probabilistic susceptibility assessment process.

Line No.	Trap Section	Section Length (km)	Dia. (in.)	Last Crack Inspection Date / Tool	Pressure Cycling	Weld Type/Manuf. Defects	Longseam Crack Failures	SCC	Overall Likelihood Grading	Consequence			Recommendation Level	Proposed Inspection Year	Additional Comments
										Normalized	Peak	[illegible]			
6B	Griffith - Sarnia	471.409	30	N/A	3	2, 4	2, 4	3	10	2.59	6.08	16	Level 2. This recommendation is based on the fact that there has not been a history of crack ruptures on this segment and the segment has the second lowest susceptibility ranking.	2005	One long seam crack-like failure occurred. This was a lack of fusion 1/4" long in the FW at MP 1566 in 1970. Proposed to inspect the last half of this pipeline in 2005 based on the fatigue analysis

Enbridge believes the best approach to confirm the sizing capability of ILI tools, supported by industry practice and referenced in both NACE 0102 and API 1163, is to use field verification to calibrate ILI data. Specifically, API 1163, section 9.3 ("Using Verification Measurements") states:

> When verification measurements are used, a comparison shall be made between reported and measured anomaly characteristics to verify the accuracy of the reported inspection results and to demonstrate that the reported results are consistent with the performance specifications. The comparison analysis shall be statistically valid and based on sound engineering practice.

Enbridge followed this approach in its 2005 ILI and dig program for Line 6B, in using field assessment data to calibrate ILI data and identify any notable deviations in ILI tool accuracy. Integration of crack and metal loss ILI data is achieved by assessment of such features through field assessments and comparisons with ILI data.

The core objective of a pipeline integrity dig program based upon ILI tool data is to remediate features that have grown through service such that they continue to meet integrity fitness for purpose criteria. Such a program also is intended to gather sufficient data to investigate and define ILI tool accuracy and integrate analysis results into possible redesign of the dig program as well as to determine the appropriate ILI inspection interval. Pipeline integrity management processes inherently include non-trivial uncertainties such as accuracy variability in key input data (e.g. ILI data) that are managed through the application of reasonable engineered safety factors and levels of conservatism (i.e. sound engineering practices).

The Line 6B integrity dig program was designed to ensure that crack features meeting fitness for purpose investigation criteria were excavated, assessed and, where necessary, repaired. The program also included a statistically relevant number of features that were assessed to support trending, calibration and verification activities. Figure 2 below is an excerpt of the feature selection algorithm, showing the crack-like and crack-field excavation criteria.

Figure 2

		TABLE I: USCD FEATURE DISPOSITION SUMMARY / MINIMUM EXCAVTION CRITERIA								
USCD FEATURE		PREVIOUS FIELD VALIDATION		2006: INTEGRITY TREATMENT OF FEATURE: PHASE I				2008 SCC INVESTIGATION GW136800-137830	2009/10: PHASE 2	2010: PHASE 3
CATEGORY	DESCRIPTOR OF INTEREST	NATURE OF FEATURE	ILI DETECTION AND SIZING ABILITY	DIMENSIONS FOR FFP	INVESTIGATION CRITERIA	NOTES	TRENDING RESULTS	INVESTIGATION CRITERIA / TRENDING OBSERVATIONS	INVESTIGATION CRITERIA	INVESTIGATION CRITERIA
Crack Like (CL)	-	High expectation of crack with variable depth along length	• Good ability to define depth and length	Use best available ILI data: (a) feature profile (b) max depth / total length	• Investigate according to FFP	• Profiles for all 25-40%, all<hydro (except 5 surface breaking laminations) • Select all with profile ffp<hydro (except 5 surface breaking laminations)	• Depth trending meets tool tolerances or is conservative for all but 1 feature • Profile max depths align well with field max depths	• Selected if on the joints of interest • None located on these joints	• Selection of CL based on fatigue growth •	• CL features based on conservative fatigue growth • CL features associated with metal loss • CL at weld within 3mi of station
Crack Field (CF)	-	High expectation of SCC	• Good ability to define maximum depth and interacting length	Conservatively use max depth and total length	• Investigate according to FFP	• Select all 25-40%, and all LI >=2.5" • use trending to confirm max depth / interacting length	• Majority SCC, some features were metal loss • Features 12.5-25, 25-40 trend well • Several features <12.5 reported between 12.5 and 25% deep	• Increase selection of CF from a high density locations; includes 25-40, 12.5-25, and <12.5 features • Trending consistent with Phase 1	• Selection of CF features to confirm growth or no growth	• CF features based on conservative crack growth • CF features associated with metal loss

Aligned with the direction contained in the industry documents, Enbridge conducted field assessments of a selection of ILI reported features in each of the depth buckets as shown in Table 1 below:

Table 1

Depth	Crack-Likes	Crack-Fields
<12.5%	20/571	73/1264
12.5 to 25	28/320	44/410
25 to 40	12/23	4/4
>40	0/0	0/0
Total Field Assessed	60/914	121/1679

Statistical analysis[1] demonstrates that the number of features assessed was a highly representative sample of the total population of features identified through the USCD ILI.

The accuracy of the USCD ILI tool was investigated and compared with the performance specification provided by PII. Table 2 summarizes the depth sizing results from field investigations for crack-likes and crack-fields.

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1 Elementary Survey Sampling, 5th ed., Richard L. Schaeffer, William Mendenhall III, R. Lyman Ott. Duxbury Press, 1996, page 99.

Table 2

	Crack-Likes	Crack-Fields
Probability of Sizing (1) accounting for one tool tolerance	98%	97% (2)
Notes: (1) Features with field assessed depths shallower than reported by ILI are included in meeting the POS value. (2) Accounting for SCC growth at 0.15 to 0.20 mm/year from the time of inspection to the time of field assessment.		

The 2005 USCD ILI tool specification states a 90% confidence of sizing features correctly within the depth bucket and accounting for tool tolerance of 40 mils. The results summarized in Table 2 provide support that the 2005 USCD ILI data was trending within expected and acceptable accuracy ranges.

Enbridge undertook an excavation program of over 75 digs and assessed over 300 crack features for ILI data trending and calibration. This program was conducted in alignment with API 1160 and 1163 and PHMSA regulations. Enbridge approached the investigation into the characterization capability of the USCD tool through field calibration activities. This applied to crack features that were coincident with corrosion. Through these calibration activities the integration of the coincident features was accomplished and represented in the resulting analysis and trends. Evidence gained from these digs demonstrated that in cases where cracks and corrosion were coincident the corrosion had no impact on the accuracy of crack sizing. See Table 3 for a summary of the dig results as part of the 2005 ILI dig program.

Table 3

	Sized Accurately or Conservatively	**One tool tolerance (0.5mm) above depth bucket**	**Two tool tolerances (1.0 mm) above depth bucket**
All Field Assessed Crack Fields(SCC)	80%	17%	3%
Field Assessed Crack Fields Coincident with Corrosion	80%	20%	0%

Note: Includes all features with ILI reported depths greater than 12.5%

Calibration results based upon the completed field assessments for all digs provided the key insights below.

- The most significant feature identified in the ILI data and field assessments had a calculated safety factor of 1.18 over the maximum operating pressure of the pipeline. This result suggested that the inspection and mitigation program had been completed in a timely manner, well before the reliability of the pipeline was compromised.

- Enbridge completed integrity digs and assessed features to achieve a statistically relevant data set to complete appropriate trending and calibration analyses and thereby supported the validity of integrity analysis conclusions and future integrity plans.

- The results of the trending and calibration analyses demonstrated that the USCD ILI tool was performing within the specifications provided by the ILI vendor for crack-likes and crack-fields. The measured Probability of Detection was 100% from data gathered through field assessments to-date. This result exceeded the Probability of Detection as stated in the USCD ILI reporting specification of 85% at reporting threshold. The Probability of Sizing met USCD ILI tool specification.

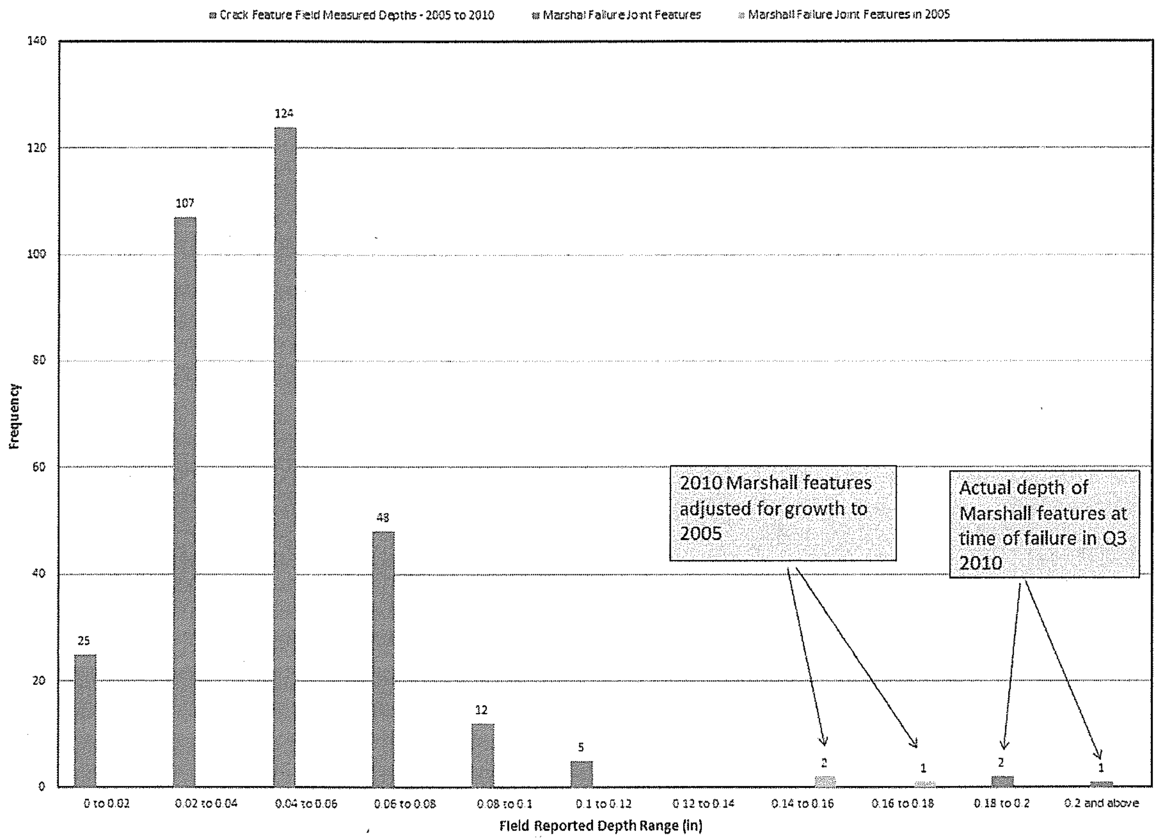
- Coincident corrosion did not appear to impact the ability of the ILI tool to size the features within the correct depth bucket.

Based upon the calibration results and crack growth rate analysis the re-assessment schedule was determined to be 2010, an interval of 5 years. This 5 year re-assessment interval was calculated to have a minimum factor of safety of two. In other words, using crack growth models developed and accepted by the industry, crack features were not expected to present an integrity threat for over 10 years. The application of a factor of safety of 2 in this case is an example where conservatism is designed into the integrity management program. The 2010 ILI assessment was underway at the time of the Accident.

To summarize Enbridge's crack inspection and integrity dig program on Line 6B in 2005-2010, it was a program conducted in compliance with industry standards and PHMSA regulations and integrated recognized approaches to investigate the accuracy and performance of the USCD ILI tool. The integrity dig program and re-assessment interval determination was based upon statistically relevant trending and calibration results. Given this extensive information collection, calibration, integration and analysis, the July 2010 Marshall feature was not predictable.

Post-Accident Inspection and Analysis. Based upon the trending and calibration activities undertaken for the Line 6B crack ILI and dig program, all evidence suggested that the USCD ILI tool was accurately reporting the size of features. However, the Marshall feature significantly deviated from the trend and calibration results. The depth distribution for field assessed crack features is included in Figure 3 below:

Figure 3



The red bars show the depth of the Marshall features as found in 2010 and the green bars show the 2010 features, adjusted for growth, as they would have appeared in 2005. The estimated depths in 2005 have been calculated post-Accident using a linear time-averaged SCC growth rate of 0.15 to 0.2 mm/year. This value is considered to be a reasonable estimate based upon industry SCC growth rate ranges and the pressure cycling spectrum that occurred at the Marshall location between 2005 and 2010. The estimated depths of the Marshall features in 2005 (the time of the USCD inspection) are well in excess of any features identified in the ILI tool report or through the subsequent dig program. Based upon the trend and calibration analyses, there was no evidence to suggest that such a significant feature existed on the pipeline.

Following the Accident, Enbridge conducted numerous excavations on Line 6B in 2010 and 2011 to collect field assessment data on cracks associated with corrosion. The results from this dig program, based on 2010 USCD ILI data and summarized in Table 4, are similar:

Table 4

	Sized Accurately or Conservatively	One tool tolerance (0.5mm) above depth bin	Two tool tolerances (1.0 mm) above depth bin
All Field Assessed Crack Fields(SCC)	95%	4%	1%
Field Assessed Crack Fields Coincident with Corrosion	93%	6%	1%

The Marshall feature in 2010, as sized and documented in the NTSB Materials Report, is calculated to be approximately 7 tool tolerances greater than the maximum 2005 ILI reported depth.

When available, it is possible to overlay the metal loss ILI and crack ILI data sets to identify those features that are coincident. Once established, an operator could choose to add the ILI data in a quantitative process in order to establish and implement an integrity dig program. An example of this process is included below and its efficacy evaluated using Line 6B data from 2010 and 2011. The features referenced in Table 5 are those that were excavated and assessed in the field and thereby provide direct comparative evidence.

Table 5

Adding the ILI reported depth of the crack with a tool tolerance to the ILI reported depth of the metal loss

	Crack Depth Bracket				>100% WT	No Cracking Found (e.g. Metal Loss)
	<0.040"	0.040" to 0.080"	0.080" to 0.120"	>0.120"		
Field Assessment Data	64	84	21	0	0	444
Prediction Using Adding ILI Data Process	0	0	13	570	30	N/A

As Table 5 shows, in over 600 features found in the field there was no feature greater than 0.120" depth. Adding the data together in Table 5 would result in almost all of the features having depths over 0.120". Adding the data together as shown in Table 5 predicted that 30 features would be 100% through-wall and require immediate mitigation actions. Field assessment results, however, demonstrated that all features were less than 0.120 inch (48%) through-wall. When assessed in the field, the majority of features (444 of 613) were corrosion with no cracking. Based on these results, adding the data together as shown in Table 5 is not a suitable engineering integrity process for Line 6B.

To summarize, trending integrity dig information from both 2005 and 2010 USCD programs demonstrates that corrosion coincident with cracking appears to have no notable impact on the crack depth estimate. Simply adding ILI reported corrosion depth to ILI reported crack depth has been shown to yield overly conservative and unreasonable results.

In order to capture a broader pipeline industry perspective on ILI detection and characterization of cracking coincident with corrosion, Enbridge retained Quest Integrity Group ("Quest") to provide an expert third party report (incorporated herein as Attachment A). Quest identified that implementation of a quantitative approach for engineering assessments of coincident cracking and corrosion as reported in ILI data integration processes is not trivial and has not been formalized within industry.

Pipeline Integrity Inspection, Technology and Analysis Conclusion. The foregoing post-Accident review and analysis indicates that the crack inspection and mitigation program that Enbridge undertook from 2005 to 2010 on Line 6B was in compliance with industry standards and regulations and that the feature that caused the loss of containment at Marshall was an anomaly that was not reasonably predictable using industry leading inspection and repair technology.

Additionally, key results from calibration activities demonstrate that the ILI data met the in-line inspection tool specifications and that complex features such as cracking coincident with corrosion were appropriately integrated into the calibration activities.

5. ENBRIDGE'S ORGANIZATIONAL RESPONSE TO THE ACCIDENT

Along with a root cause investigation, Enbridge conducted a comprehensive cross-functional self-examination following the Accident. As a result of Enbridge's experience in responding to this Accident, the comprehensive investigation and self-examination of its pipeline integrity processes and management systems and the NTSB's investigation, Enbridge implemented a number of additional measures, procedures and process modifications that have collectively already significantly reduced and will continue to reduce the risk of a loss of containment, improve its monitoring of and responding to alarms in the control room and strengthen its response to leaks and releases. Many of these modifications and improvements include ongoing review and improvement mechanisms that will promote increased preparedness and strengthen Enbridge's management systems.

In addition to the measures implemented in Enbridge's integrity inspection and analysis program discussed previously, other significant measures are described below.

Pipeline Control Systems and Leak Detection (PCSLD)

A. Enbridge has, for over 60 years, worked to be at the forefront of pipeline control and leak detection technology, and has pursued this goal with technical personnel in various organizational structures. In October 2010, Enbridge pulled these functions together and created the PCSLD department, which is Director-led and reports to a Vice President. This establishes a single area of accountability in relation to leak detection capability, safe and reliable pipeline control systems and improved operator information systems. Staff and contractor additions in 2010-2012 resulted in a doubling of the PCSLD workforce. Enbridge created three sub-departments under the PCSLD department: (i) the Leak Detection sub-department which is comprised of three teams: Maintenance and Integration, Assessment and Support and Testing and Research; (ii) the Pipeline Control Systems sub-department which is comprised of three teams: SCADA Services, Control Systems CAN and Control Systems USA; and (iii) the Quality and Compliance sub-department.

B. Four Leak Detection Analyst procedures have been implemented since July 2010: the leak detection escalation process; shift change sheet; alternate leak detection recommendation procedure; and analysis and communication procedure. Procedures for the new Control Room Management regulation are to be implemented by August 2012. Enbridge also established a Quality Management System (QMS), with a view to more effective execution of work activities meeting pre-defined quality objectives.

C. The Leak Detection Analyst Training Program has been enhanced in several areas including on-the-job training, training program layout, readiness assessment and communications with CCO Personnel.

D. Leak Detection System Changes: Continuous improvement plans have been developed and are being implemented to tune the Leak Detection Systems for optimal performance. A leak detection equipment design standard has been developed to ensure leak detection performance standards will be met on new pipelines. Research initiatives are underway to assess commercially available leak detection technologies and to determine if there are complementary strategies to further enhance leak detection performance.

E. Leak Detection Instrumentation: Assessments and planning of instrumentation additions and upgrades required to improve the performance of the leak detection system, and ensure it consistently meets or exceeds Enbridge internal performance targets have been completed. A Leak Detection Instrumentation Improvement Program has been initiated that will add and upgrade instrumentation across the system based on the assessment results. The establishment of a maintenance management program is underway. This program will further enhance the existing program by formalizing the inventory and management of critical leak detection equipment.

F. SCADA/Pipeline Control System Changes: Initiatives are underway to seek to improve controller decision support systems. This includes active projects which will deliver tools to support the analysis of column separation as well as potential leak events, and implementation of incremental expert systems to support alarm analysis. On-going improvements to historical data storage and retrieval have been completed at most terminal and pump stations, resulting in the archiving of high consequence data at a resolution frequency of approximately one second. Evaluation of the current communication mechanisms, including RTU infrastructure and physical communication layers, is in progress.

Pipeline Control (including Control Center Operations)

G. To better align, focus, manage span of control and workloads, Pipeline Control now reports to Operations rather than to Customer Service in the previous reporting structure. Enbridge created a new Vice President for Pipeline Control. Enbridge added ten new Senior Technical Advisors to support abnormal operating conditions and on-going mentorship. Training, engineering and Control Center operator staff has been augmented. Seven new operator positions were added in the last year to accommodate growth and expansion, reassignments, replacements and workload balancing.

H. Key Procedures and Process Enhancements. Enbridge has revised and enhanced many procedures seeking to improve communication and decision making, including procedures for handling pipeline start up and shutdown, Leak Detection System alarms and communication protocols and suspected column separations (Enbridge developed an analysis form and a list of common column separation locations). Enbridge also revised and enhanced its procedure review and revision process and developed a pipeline control administration on-call handbook and specific Life Saving Rules for the CCO.

I. Control Room Management (CRM) – 49 C.F.R.195.446. The Control Center's CRM Plan was revised, updated and in place August 1, 2011 to meet the requirements of this recently promulgated rule. It consists of detailed processes and procedures to provide control room management in the following areas: roles and responsibilities; provide adequate information – SCADA; provide adequate information – shift change; fatigue mitigation; alarm management; change management; operator experience; training; compliance validation; and compliance and deviation. A number of the sections were implemented in October 2011 with the remaining on track for implementation by August 2012.

J. Training Development and Enhancements. All pipeline operators have received enhanced hydraulics training which included the following: a re-emphasis on the need to think leak first and adhere to emergency procedures, an overview of MBS system and procedures, refresher training on the "10-minute rule" and compliance to procedures, clarification of the roles and responsibilities between operators and shift lead as well as between operators/shift leads and MBS Analyst, column separation analysis, incident investigation (including SCAT) for all Managers, Technical Services, Engineers, Shift Leads and Training Staff. Other training includes Lifesaving Rules and Respectful Workplace Training for all Pipeline Control Staff; augmentation of Emergency Response Training in the Control Center to include two full days in 2012; Fatigue Management Training; Mentor Selection Process and Training; MBS System Training and Formalized Communication Protocols; and on-call training for Pipeline Control Administrative staff.

Public Awareness

K. At the time of the Accident Enbridge had a well-established ongoing Public Awareness Program and had recently provided a safety awareness training program to both Marshall fire departments. In an attempt to further enhance the effectiveness of this program, in May 2011 Enbridge established a U.S. Public Awareness Committee consisting of internal stakeholders including field operations and management, right-of-way, compliance, integrity and public affairs, and meets four times annually. The committee is tasked with (a) maintaining effective communications with other stakeholders; (b) preparing for successful regulatory inspections and audits; (c) implementing standardization of organization wide programs; (d) an annual review and sign-off of the Public Awareness Program; (e) an annual Review of the Public Awareness Performance Measures; (f) reviewing Industry best practices; (g) achieving full participation among the committee members; and (h) establishing accountability and consistency.

L. A Public Awareness Documentation Database, which is accessible online by all Enbridge U.S. employees, has improved the documentation of supplemental Public Awareness contacts, including face-to-face meetings, letters, emails, telephone calls and events. Improvements since the roll out of the database in 2010 have been based on user experience and are focused on continuous improvement of our documentation process.

M. Training is provided annually for field employees in each liquids region and gas district to help them better understand their role in the Public Awareness Program. In 2011, Enbridge provided additional training for more than 500 field employees. In Q4, 2012, online training will be rolled out for all employees to complete, regardless of whether they work in a field location or in an office. In addition, a program to provide in-person and online training for third party emergency responders in Enbridge's areas of operation is currently in development and will launch in Q4, 2012. The training will cover emergency preparedness communications, potential hazards and other relevant topics.

N. Focus group testing of the Public Awareness brochures for all audiences was conducted in Q1, 2012. Based on the feedback received from participants, several changes were made to the 2012 brochures. Major changes include re-focusing emphasis placed on the emergency numbers and reducing non-emergency phone numbers to one toll-free number to improve clarity on which number to call in emergency vs. non-emergency situations. The entire "Affected Public" (as defined by applicable regulations) audience now receives a magnet with the annual brochure mailing which includes the appropriate emergency number for their area. Through the engagement of Enbridge's Government Affairs team, the public official mailing list has been improved to better target state and federal public officials. In addition, supplemental mailings have been sent to public officials to remind them of Enbridge's Public Awareness efforts, including 811 Day, National Safe Digging Month and the delivery of Public Awareness calendars to their constituents.

6. CONCLUSION

On July 25, 2010, Line 6B was operating normally when experienced Enbridge control room personnel shut it down to facilitate a routine scheduled delivery into Stockbridge. Enbridge utilized state-of-the art testing on Line 6B, particularly in the six years prior to the Accident, and has approximately 60 years of experience operating what today is North America's longest liquids pipeline delivery system. Enbridge had no reason to expect a failure of Line 6B.

Because a significant loss of pressure is normal during a shutdown, the experienced crew in the control room misinterpreted the significance of alarms and thus focused their trouble shooting over the next seven hours on resolving the alarms, not addressing a potential loss of containment. Moreover, notwithstanding multiple 911 reports of petroleum odors in the area, an active public awareness program and investigations by two separate fire departments, Enbridge was not contacted and the existence of the failure was not identified for over 17 hours.

Once Enbridge was advised that oil had been spotted in Talmadge Creek, Enbridge management responded swiftly and decisively at the highest levels. The CEO was on the scene before the day was over, and spent the next two months overseeing the organization's extensive response efforts. He took full responsibility, pledging that Enbridge would address the impacts of the release on the natural environment and would address the financial and other needs of individuals and businesses in the community. Enbridge is doing so still today. The crude oil has been virtually all cleaned up and product has continued to flow through Line 6B since September 2010.

Enbridge believes that its pipeline integrity process and management in 2010 were state of the art and in compliance with all applicable regulatory requirements. However, it now, with the benefit of the reviews of the Accident, appreciates the limits of what it and the industry knew then, and what it might have been able to do differently in order to identify the potential problem in advance. Enbridge has learned from this Accident and has implemented a number of measures that will help Enbridge and the industry prevent the recurrence of accidents like this one in the future. Enbridge remains committed to operating to high standards and to avoiding releases.

Attachment