Enbridge Pipelines (Lakehead) L.L.C.
119 N 25th Street E
Superior, WI 54880
www.enbridgepartners.com

Shaun G. Kavajecz, Manager
Pipeline Compliance
Tel 715 394 1445
Fax 713 821 9428
shaun.kavajecz@enbridge.com

April 15, 2011

VIA ELECTRONIC TRANSMISSION

Mr. David Barrett
Director, Central Region
PHMSA Office of Pipeline Safety
901 Locust St., Suite 462
Kansas City, MO 64106

Re: Line 6B – Corrective Action Order -- Enbridge Response to March 18, 2011 Notice of Required Modifications to Integrity Verification and Remedial Workplan

Dear Mr. Barrett:

Enbridge Energy, Limited Partnership ("Enbridge") is in receipt of the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") March 18, 2011 "Notice of Required Modifications" to Enbridge's Line 6B Integrity Verification and Remedial Workplan (Notice"), and hereby responds to that Notice.

This correspondence and the two attached amendments provide an update on the status of remaining CAO-required actions and items identified in Enbridge's February 17 letter, amend Enbridge's previously submitted IVP to incorporate the additional measures with a consistent level of technical detail in response to the PHMSA Notice, and describe measures by which Enbridge will assess and incorporate rehabilitation, repair and replacement criteria into Line 6B's IVP and long-term integrity management program**.**

Pursuant to the Corrective Action Order issued by PHMSA dated July 28, 2010 ("CAO"), as well as the amendment thereto dated September 22, 2010, Enbridge has nearly completed all required corrective actions as defined within the CAO. Enbridge submitted its IVP on September 26, 2010 in accordance with the CAO. That IVP detailed and defined the manner in which Enbridge would complete investigative and corrective measures to demonstrate the safe and environmentally sound operation of its Line 6B pipeline (a) prior to initial restart, and (b) during subsequent activities while operating under prescribed reduced interim operating pressure. The IVP also set forth a plan for maintaining and monitoring the long-term integrity of Line 6B to ensure the ongoing safe operation of the line prior to any authorized return to pre-release operating pressure.

As noted in our letter of February 17, 2011, Enbridge has continued to refine, enhance, and supplement the activities defined in the originally submitted IVP to ensure that Enbridge's approach to the integrity verification of Line 6B is strategically and technically sound. Enbridge has integrated further investigative and assessment measures into its overall plan to demonstrate Line 6B integrity and long-term safe operability, as described in that letter. Many of these measures address the issues raised in PHMSA's Notice.

Status - (Amended CAO Items 5 (G) - (J)):

Successful completion of required ILI runs; remedy of 329 features through rehabilitation, repair and/or replacement; and pipe replacement of St Clair River crossing:

Enbridge has completed performing both a transverse field in-line inspection capable of identifying metal loss, as well as an ultrasonic technology in-line inspection capable of detecting cracks. Additionally, reporting of in-line inspection results has been completed in accordance with the CAO.

Enbridge has regularly reported to PHMSA on the ongoing progress of the aforementioned CAO items. Pipe replacement segments that were completed the week of March 7, 2011 concluded the remediation of the last remaining features, out of the 329 features requiring rehabilitation, repair or replacement, within a 180-day duration specified in the CAO.

Enbridge completed the installation of new pipe to replace its existing Line 6B St. Clair River crossing, utilizing a horizontal directional drill technique to install the new pipe. The replacement pipe has been successfully installed underneath the St. Clair River and awaits final tie-in, currently anticipated for June, 2011, in advance of the CAO-prescribed deadline of one year following post-release line restart.

Theoretical remaining flaw calculation and ensuing Interim Engineering Assessment:

Prior to restart of Line 6B, Enbridge evaluated the potential for theoretical remaining flaws on the pipeline and took a conservative approach to define the predicted life of such a feature, should one exist, at the reduced operating pressures. This resulted in a conservative timeline by which new safety margins ensured that the risk of such a failure was mitigated, while further investigative and validation activities produced results from in-line Inspections ("ILI") and excavation assessments could be reviewed.

With the IVP ILI program complete, Enbridge was able to reassess the original theoretical remaining flaw calculation timeline. Enbridge's Interim Engineering Assessment report dated March 25, 2011 (previously submitted) summarizes the scope and results of the program. As evidenced in the report, subsequent analysis has allowed Enbridge to conclude that growth rates would not pose a risk to the pipeline under the current reduced operating pressures, and afford conservative safety margins in excess of 5 years, irrespective of the ongoing inspection and repair program.

Relative to PHMSA directives, Line 6B is currently operating at an interim reduced operating pressure which is 80% of the pressure experienced on the pipeline prior to the Marshall incident. As stated in section 4.3 of the IVP, these pressure limits will remain in place until Enbridge completes a final comprehensive engineering assessment, which incorporates and defines Line 6B hydrotesting and pipe replacement considerations, and until approval from PHMSA is received to increase pressure beyond the current restriction.

March 11, 2011 PHMSA Notice of Required Modification

As per Enbridge's originally proposed IVP, as well as subsequent meetings and on-going dialogue with PHMSA, Enbridge believes that its original IVP provided sound rationale for ensuring safety margins and safe operations for the short- and near-term. Assessment of additional technical detail generated from the recently completed investigative activities will allow Enbridge to make sound technical decisions on long-term integrity plans.

PHMSA's amended CAO Item 5 (C) requires that "…evaluation methods used must be technologically appropriate for assessing the pipeline based on the type of failure that occurred on July 26th, 2010 and should include consideration of pressure testing and/or additional in-line inspections supplemented by complimentary direct assessment, as appropriate."

Enbridge has completed the in-line inspection utilizing ultrasonic technology capable of detecting cracks in accordance with the CAO. Additionally, Enbridge's IVP proposed an ILI validation method whereby we employed an additional in-line inspection technology using an alternative crack inspection tool (GE's DUO Tool), in both a traditional 45-degree sensor arrangement in one trap-to-trap pipe segment, and a developmental 60-degree sensor arrangement in the other segment. Enbridge planned and has completed a second crack inspection on Line 6B using a new generation of ultrasonic technology (commonly referred to as "phased array" ultrasonics). Integration of the results from both crack inspections is underway to support the crack inspection accuracy validation process.

Enbridge understands PHMSA's need for appropriate technical detail to assure the long-term integrity of Line 6B, and shares the same objective. Enbridge believes that some time is required to appropriately assess the comprehensive amount of information that has been generated resulting from the investigation and subsequent assessment activities that have been just recently completed. It remains Enbridge's position that until such time as all aspects are evaluated and the final Engineering Analysis completed, it is premature to make firm long-term integrity decisions as they relate to pressure testing and pipe replacement, or other potential mitigating alternatives.

To this end, our primary efforts have been focused around ensuring the safe and environmentally sound operation of Line 6B at its currently reduced operating pressure. We are now focused on the investigative and corrective actions needed to mitigate potential risk through the rehabilitation, repair and replacement programs that have just recently been completed on Line 6B. At the same time, we are maintaining operations at the reduced operating pressure until our measured approach leads us to appropriate and technically sound long-term integrity management decisions, including consideration for pipeline pressure testing and repair.

In an effort to seek further interim opportunities to validate ILI results, and as defined in our February 17, 2011 letter, Enbridge plans to utilize pipe removed during the recently completed pipe replacements to perform pressure testing and other techniques to validate/confirm recent ILI results.

Enbridge's amendments to its IVP incorporating new items to Section 3, specifically item 3.6.3 – Long Term Verification Plan – Specifics for Line 6B, and item 3.6.4 – Considerations for Integrity Validation Alternatives, are attached. Consistent with PHMSA's request, the IVP amendments specifically address Enbridge's plans and views with respect to pipe replacement and hydrostatic pressure testing, among other integrity verification measures. Generally, these new

plan amendments are intended to identify the plan, schedule and decision-making methodology for further assessment of the integrity of Line 6B through the iterative analysis of the multi-faceted integrity assessment activities being executed. This will allow Enbridge to make the most informed decisions on the long-term integrity strategy and programmatic requirements for Line 6B.

Conclusion:

Enbridge has completed rehabilitation, repairs and pipe replacement to remedy defined features in accordance with the CAO. We have also completed CAO prescribed ILI's as well as an additional in-line inspection and assessment using an alternative technology to supplement and validate the CAO required ILI's. The data generated from these activities has allowed Enbridge to evaluate and re-establish a new theoretical critical flaw calculation that demonstrates conservative safety margins exist in excess of 5 years at the current restricted operating pressures, irrespective of ongoing future mitigation, as documented in the Interim Engineering Assessment. Enbridge has amended its IVP to include additional sections relative to the sequencing of long-term integrity measures, including hydrotesting and pipe replacement alternatives. The IVP amendments set forth a plan for maintaining and monitoring the long-term integrity of Line 6B to ensure the ongoing safe operation of the line prior to any authorized increase from current operating pressure.

Enbridge will continue to maintain active communications and dialogue with PHMSA as we move toward completion of the final Engineering Analysis and implement the long-term integrity management plan required to maintain the pipeline and restore operating pressures, per the CAO.

Please contact me if you have any questions or would like to arrange a conference call to discuss any items addressed in our response.

Sincerely,

Shaun Kavajecz,
Manager, Pipeline Compliance,
Enbridge Pipelines (Lakehead) L.L.C.

attach

3.6.3 Long Term Verification Plan – Specifics for Line 6B

The plan for verification of Line 6B's integrity condition in the long term includes the following activities:

1. Threat specific in-line inspections
2. Integrity digs to repair the pipeline and collect data for tool calibration analyses
3. Evaluation of tool calibration results
4. Consideration of Pipe Replacement and Hydrostatic Pressure Testing
5. Re-assessment of the pipeline condition

Beyond the information included below, Enbridge will be in a position to communicate additional specifics regarding the long term verification plan to PHMSA prior to the end of September 2011. This timing is driven by short term integrity verification activities that are currently progressing or are planned for Q2 and Q3 2011.

<u>In-Line Inspections</u>

Immediately following the re-start of Line 6B, and in accordance with the PHMSA CAO, Enbridge initiated the inspection of the pipeline for cracking using the GE CD+ ILI tool and for axially oriented corrosion using Rosen AFD ILI tool. The new in-line inspection data provides detailed information about the integrity condition of the pipeline and will support the creation of the appropriate plans to safely return Line 6B operating pressures.

In order to provide additional supporting information for the verification of the pipeline's cracking condition Enbridge conducted an additional ultrasonic crack inspection utilizing a phased array ultrasonic crack tool (GE DUO tool), in compliance with PHMSA's CAO and Enbridge's corresponding IVP. The data from the phased array inspection will be compared to the data obtained through the GE CD+ inspection. This work has recently been initiated as the final reports have been received and may result in additional investigative excavations and detailed analysis investigations by the ILI tool vendor. Results of this investigation will be integrated into the overall assessment of the pipeline and may adjust the long- term integrity plan.

Enbridge is currently in the process of re-inspecting the entire pipeline for corrosion features using both the magnetic and ultrasonic technologies. This data will update our already comprehensive understanding of the corrosion condition of the pipeline and allow for the calculation of updated corrosion growth rates. The final reports for these inspections are expected to be received later in 2011 with the corrosion growth rate analyses completed shortly afterwards. This updated information will further support the development of the long term integrity plan.

<u>Integrity Digs and Calibration</u>

There have been over 400 digs completed on Line 6B since the Marshall incident. These digs have generated NDE information on over 10,000 features that are currently being utilized in calibration and

verification studies. Integrity digs are planned to continue throughout 2011 and into 2012, the total number of which will depend upon the results from the calibration analyses and other integrity driven actions (such as possible pipe replacement) that are currently under evaluation.

Detailed trends of ILI tool performance have been created for the cracking and corrosion inspections. The results of which have been considered in the creation of the excavation criteria described in section 3.6.4. In particular, non-conservative ILI tool calls are carefully considered and evaluated to determine the potential impact to our understanding of the pipeline's condition. These trends will continue to be updated and evaluated as additional dig information is gathered.

The document "Interim Engineering Assessment of Cracking on Line 6B" previously submitted to PHMSA includes a summary of the processes involved in the assessment of the ILI and dig data in order to reach conclusions regarding the integrity condition of the pipeline.

Consideration of Pipe Replacement and Hydrostatic Pressure Testing

Prior to the Marshall incident Enbridge was in the process of developing and executing a pipe replacement project on Line 6B downstream of Stockbridge. Following the Marshall incident Enbridge replaced pipe within the 180-day time limit imposed by PHMSA to address the 180-day corrosion conditions identified through ILI, to the extent CAO time constraints afforded. Based on cumulative assessment results to date, Enbridge is currently assessing whether additional pipe replacement is warranted and will conclude the assessment and plan for pipe replacement, as warranted, prior to requesting any change in current operating pressures. Additional information on pipe replacement is included in section 3.6.4.

Prior to re-starting Line 6B a hydrostatic validation pressure test was conducted on the section of Line 6B from Marshall pump station to a location 13 miles downstream. This test was conducted successfully and supported the conclusion that the pipeline was safe to re-start at the interim reduced operating pressures. Additional pressure tests are planned for select sections of pipe recently removed from Line 6B as part of the pipe replacement activities completed in February and March of 2011. The pressure testing of select replaced pipe is anticipated to occur in July of 2011 with the results of this work integrated into the development of the long term integrity plan.

A decision regarding the technical validity of conducting additional hydrotests on Line 6B will be made as additional information from the short term integrity verification activities becomes available. In particular the results from the following activities are considered germane to the understanding of the uncertainties associated with ILI defect detection, the potential implementation of a hydrotesting program and a return to normal operating pressures.

- Ongoing ILI calibration through an extensive dig program
- Results from the verification analysis on the crack ILI data from the two different ultrasonic technologies utilized to inspect the pipeline

- The results from the testing of the pipe removed from Line 6B during the pipe replacement activities
- The results from the NTSB investigation
- Results from the 2011 corrosion inspections

If hydrotesting is included within the integrity verification plan it will be conducted as soon as practicable following the completion of the short term integrity verifications, and not more than two years prior to the next scheduled crack inspection. Additional information on hydrotesting is included in section 3.6.4.

Re-Assessment

The current long term integrity plan for Line 6B includes the re-assessment of the entire pipeline with corrosion, crack and geometry ILI tools in 2013.

3.6.4 Considerations for Integrity Validation Alternatives

General

The core objective for a monitoring and mitigation program is to maintain a safe and reliable pipeline. The specific approaches and implementation methods that form the overall program must be capable of achieving the desired pipeline reliability while considering factors such as the confidence in the integrity data, the pipeline operational parameters, and the relative costs and benefits of the integrity validation options.

Rehabilitation

Work includes elements such as: Excavation of the target pipeline, removal of the existing coating, preparation of steel surface (sandblasting), non-destructive examination (scope based partially on ILI data), repairs as required, re-coating, re-burial, and reclamation.

1. Small Scale Rehabilitation (Less than 2000 ft length)

   Enbridge conducts excavations to complete investigations and repairs on the pipelines. Integrity data on the pipeline sections upstream and downstream (typically in the range of 100 ft to 500 ft) of the area targeted for investigation is reviewed by integrity analysts. An assessment is performed to determine if extending the pipeline repair work scope to include rehabilitation of these pipe sections is appropriate. Generally, if it determined that a pipeline repair is likely to be required in the immediate area within the next 10 years the additional section of pipeline is exposed and rehabilitated. Factors considers in such an assessment include:

- Anticipated coating condition and coating performance.
- Cathodic protection data.
- Number and significance of pipeline features such as corrosion, cracks and dents.
- Terrain and access conditions. Examples include swamps, landowner concerns, environmentally sensitive areas.

2. Large Scale Rehabilitation (> 1 mile)

   The decision to complete large scale rehabilitation is based upon an assessment of the economic advantages of rehabilitation verses targeted pipeline repairs or pipe replacement. The economic evaluation has to consider all the direct costs of completing the work safely and the indirect costs of pipeline shutdowns or pressure reductions during work activities. Generally, a rehabilitation project becomes more economically feasible with a high density of low level pipeline features that are expected to grow over time.

Pipeline Replacement

Discrete pipeline repairs (i.e. excavation and repair of 10 to 40 ft length of pipe) are an effective method of maintaining a safe and reliable pipeline. However, if the density of near-term (0 to 2 years) and predicted future repairs (3 to typically 10 years) is high it may be more economically attractive to replace a section or sections of pipeline instead of conducting the discrete repairs. Other factors that are considered in the evaluation of potential pipe replacement sections include overall risk control enhancements. Also, locations of higher operating pressure may be prioritized over low operating pressure locations for pipe replacement. The integration of risk control into the assessment is situational and assessed on a case by case basis.

For Line 6B specifically, an unclassified cost estimate for pipe replacement ranges between $3.5MM to $5MM for every mile replaced when assuming a contiguous length of at least 5 miles. Shorter sections of pipe replacement can be significantly higher due to high proportional overhead costs such as tie-ins. Engineering and execution challenges (such as site congestion / access issues) can impact the decision of whether pipe replacement is the preferred mitigation option. Generally, sections of Line 6B that are anticipated to require greater than 25 repairs per mile over the next 10 years are potential candidates for pipeline replacement.

Line 6B has recently been inspected with sophisticated in-line inspection technologies that detect and characterize features of interest such as corrosion, cracks and dents. Additional corrosion inspections using both magnetic and ultrasonic technology are currently underway and planned for later in 2011. All of the ILI data along with detailed assessments of pipeline feature growth mechanisms is being integrated to evaluate the number of pipeline repairs that will be required in the short term and anticipated to be required within the next 10 years. The criteria currently being applied in this assessment are included below. An ILI data calibration effort is ongoing and will continue throughout 2011 and into 2012, the results of which will be integrated into our long term integrity plan for Line 6B. As such, there is a possibility of revisions as the calibration effort continues.

Corrosion	1	All features with a depth > 50% of wall thickness.
	2	The fitness for purpose evaluation identifies a safety factor of < 1.39.
Cracks	1	All features with a reported depth > 0.120 inches
	2	All reported crack-like and crack-field features with reported lengths > leak/rupture boundary within 5 miles of pump station discharge (i.e. higher operating pressure locations).
	3	All reported crack-field features with a longest crack indication > leak/rupture boundary.

	4	The fitness for purpose evaluation identifies a safety factor of < 1.25.
	5	All features with “non-determinable” radial position
Geometry	1	All features identified as meeting 49 C.F.R. 195.452

Feature growth rate modeling has been completed to estimate the location and number of future repairs on Line 6B. For corrosion features, the growth rate has been established by comparisons between ILI data sets gathered over the past 7 years. In summary, the corrosion growth rate utilized for the assessment is 1.73% through wall per year. Additional information is included in the September 7 submission to PHMSA. The corrosion growth rate information will be updated upon receipt of the reports from the 2011 in-line inspections. Stress corrosion cracking growth rates have been calculated based upon the equation developed by Dr. John Beavers of DNV. Reference 2007 NACE paper. Fatigue crack growth has been based upon the Paris Law method using API upper bound values and “at site” pressures.

Further to the current pipe replacement assessment it is planned to update the assessment in 2013 after a comprehensive re-inspection program on Line 6B using in-line inspection tools for corrosion, crack and geometry features in 2013.

Hydrostatic Pressure Testing

Monitoring of the Enbridge pipeline condition through the use of hydrotesting has largely been replaced by the use of high resolution in-line inspection tools. Enbridge still maintains hydrotesting as a pipeline integrity condition monitoring method, its application can be characterized as follows:

1. Hydrostatic testing to increase the maximum operating pressure of the pipeline.

2. An effective in-line inspection tool is not available that can assess the pipeline for anticipated integrity threats and hydrotesting can be shown to provide assessment benefits. This can occur when an ultrasonic tool is required and a liquid couplant is not available.

3. The pipeline is not capable of being inspected with in-line inspection tools. This can be the case if a pipeline has tight bends, restrictive valves or such physical impediments. All Enbridge transmission pipelines are capable of being inspected with the best in-line inspection technologies.

4. Hydrotest to validate and confirm assumptions. When using in-line inspection technology to monitor the integrity condition of a pipeline the data captured has to be validated and the accuracy defined. Methods to validate the effectiveness of monitoring integrity through the use of in-line inspection technology exist within the pipeline industry. Probability of detection (POD), probability of identification (POI), and probability of sizing (POS) are examples of

potentially useful statistical techniques to judge to the quality of the inspection data. If the results of such assessments demonstrate a degree of uncertainty with the detection and characterization of pipeline features (i.e. the POD value is low) such that the pipeline cannot be reliably operated Enbridge must take additional actions. These actions can include:

- Re-inspection of the pipeline with the same in-line inspection tool. This approach may be taken if the original data is unusually degraded and of a lower quality than anticipated
- Inspection with a different technology (ie. Ultrasonic vs. Magnetic).
- Additional calibration investigation excavations.
- Hydrotesting a section or sections of the pipeline.

Specifically for Line 6B, if non-ILI detected near critical features were identified during field investigations an assessment would be required to determine if hydrotesting was an appropriate activity. An important consideration prior to implementing a hydrotesting plan is the potential damage that hydrotest pressures could cause. Examples of this issue include crack initiation at locations of otherwise non-injurious manufacturing features, growth of existing sub-critical cracks and / or re-initiating otherwise dormant stress corrosion cracking colonies.

Note: The ILI tool calibration analyses are trending conservatively or accurately representing the condition of the pipeline. No near critical pipeline features have been identified during field investigations that were not detected by the appropriate ILI technology.

The overall approach to validate the integrity condition of Line 6B in preparation for a return to normal operating pressures is under development as the short term integrity verification activities continue. The approach employed will be designed to accomplish the long term safe and environmentally sound operation of the pipeline.